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November 14, 2011

VIA E-FILING
Ms. Jocelyn D. Boyd
Chief Clerk of the Commission
SC Public Service Commission
P. O. Drawer 11649
Columbia, SC 29211

RE: Application Duke Energy Carolinas, LLC for Authority to Adjust and Increase the Company's Electric Rates and Charges
Docket No.: 2011-271-E

Dear Ms. Boyd:

Enclosed please find for filing the Direct Testimony of Kevin W. O'Donnell filed on behalf of the South Carolina Energy Users Committee ("SCEUC") in the above-captioned matter. By copy of this letter, I am serving all parties of record.

If you have questions, please do not hesitate to contact me.

Sincerely,

ELLIOTT & ELLIOTT, P.A.

Scott Elliott

SE/jcl

Enclosure

cc: All parties of record w/enc.

BEFORE

SOUTH CAROLINA PUBLIC SERVICE COMMISSION

DOCKET NO. 2011-271-E

In the Matter of:

Application of Duke Energy Carolinas., LLC	)	
For an Adjustment in Rates and Charges	)	**Docket No. 2011-271-E**
Applicable to Electric Service in South Carolina	)	

Direct Testimony

of

Kevin W. O'Donnell, CFA

On Behalf of

South Carolina Energy Users Committee

November 14, 2011

BEFORE

SOUTH CAROLINA PUBLIC SERVICE COMMISSION

DOCKET NO. 2011-271-E

DIRECT TESTIMONY OF KEVIN W. O'DONNELL, CFA

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of South Carolina Energy Users Committee (SCEUC), which is an industrial trade association in South Carolina. Many of SCEUC's members take retail electric service from Duke Energy Carolinas, LLC (Duke or the Company) and will be impacted by the proceedings in this case.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (NCUC). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm. I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission (SC PSC), the Virginia State Commerce Commission, the Minnesota Public Service Commission (MPSC), and the Florida Public Service Commission (FL PSC). In 1996, I testified before the U.S. House of Representatives, Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A to my direct testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present to the Commission my findings as to the proper return on equity and capital structure for use in this proceeding.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- the proper return on equity on which to set rates for Duke in this proceeding is 9.50%;
- the proper capital structure to use in setting rates should be capped at 53% common equity and 47% debt;
- the overall rate of return that Duke should be allowed in this case is 7.58%;
- the return on equity recommended by Company Witness Hevert is excessive and unreasonable;
- Duke's voluntary opportunity program (VOP) expenses of $23.8 million should be amortized over 5 years, not the three years requested by the Company;
- Duke's request for accelerated depreciation should be denied;
- Duke's request to amortize $7.2 million in pension litigation expense should be disallowed;

- I agree with Duke Witness Stillman's recommendation of the use of the CP methodology for allocation of fixed generation plant investment; and
- in an effort to stimulate peak load reduction throughout the Carolinas, Duke should implement a coincident peak (CP) rate design and provide more economical time-of-use rates;
- Duke should offer the transformation discount to all customers and not just new customers;
- Duke's rate increase assigned to Rate MP customers is not supported by evidence in the record; and
- The rate increases associated with this rate case should be phased in over two years.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony is divided into nine sections as follows:

I. Economic and Legal Guidelines for Fair Rate of Return

II. Cost of Capital

A. DCF Analysis

B. Comparable Earnings Analysis

C. Return on Equity Recommendation

D. Capital Structure

E. Review of Company Witness Hevert's Testimony

III. Accounting Adjustments

IV. Cost of Service Study and Rate Design

V. Summary

I. ECONOMIC AND REGULATORY POLICY GUIDELINES FOR A FAIR RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE FAIR RATE OF RETURN THAT DUKE SHOULD BE ALLOWED THE OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the procurement of natural gas and generation of electric power and energy is spreading, the delivery of these products to end-use customers will continue to be considered a natural monopoly for the foreseeable future. When it is deemed that a perceived natural monopoly does in fact exist, regulatory authorities regulate the service areas in which regulated utilities provide service, e.g. by assigning exclusive franchised territories to public utilities or by determining territorial boundaries where disputes arise, in order for these utilities to provide services more efficiently and at the lowest possible cost. In exchange for the protection of its monopoly service area, the utility is obligated to provide adequate service at a fair, regulated price.

This naturally raises the question - what constitutes a fair price? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair rate of return on invested capital. This fair rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Obviously, since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new capital on reasonable terms.

Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

Regulatory law and policy recognize that utilities compete with other forms in the market for investor capital. In the case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn:

In that case, the U.S. Supreme Court specifically stated that:

> "...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return,. moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital." (320 U.S. at 603)

II. <u>COST OF COMMON EQUITY</u>

Q. PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF FAIR, JUST, AND REASONABLE RATES FOR THE UTILITY.

A. In South Carolina and in all regulatory jurisdictions, a utility's rates must be fair, just, and reasonable. Regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a fair rate of return on the capital invested in the utility's facilities, such as power plants, transmission lines, distribution lines, buildings, vehicles, and similar long-lived capital assets. Utilities obtain capital funding through a combination of borrowing (debt financing) and issuing stock. The allowed return on equity (ROE) is the amount that is determined to be appropriate for the utility's common stockholders to earn on the capital that they contribute to the utility when they buy its stock. If the regulatory authority sets the ROE too low, the stockholders will not have the opportunity to earn a fair return; if the regulatory authority sets the ROE too high, the customers will pay too much, and the resulting rates will be unfair and unreasonable

Q. HOW DO REGULATORY AUTHORITIES GO ABOUT DETERMINING WHAT IS A FAIR RATE OF RETURN ON EQUITY?

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are "Discounted Cash Flow" or "DCF" analysis and "Comparable Earnings Analysis." Sometimes a technique called the "Capital Asset Pricing Model" or "CAPM" method is used. I believe that the two most useful methodologies are DCF Analysis and the Comparable Earnings Analysis.

A. Discounted Cash Flow (DCF) Analysis

Q. CAN YOU PLEASE EXPLAIN THE DISCOUNTED CASH FLOW METHOD?

A. Yes. The DCF method is a widely used method for estimating an investor's required return on a firm's common equity. In my twenty-six years of experience with the Public Staff of the North Carolina Utilities Commission and as a consultant, I have seen the DCF method used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF method, either by itself or in conjunction with other methods such as the Comparable Earnings Method or the Capital Asset Pricing Model, in their analyses.

The DCF method is based on the concept that the price which the investor is willing to pay for a stock is the discounted present value or present worth of what the investor expects to receive as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation can be ignored since appreciation in price is only realized when the investor sells the stock. Therefore, the only income that the investor will receive from the company in which it invests is the dividend stream. Mathematically, the relationship is:

Let D = dividends per share in the initial future period
g = expected growth rate in dividends
k = cost of equity capital
P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D\,(1+g)}{(1+k)^2} + \frac{D\,(1+g)}{(1+k)^3} + .. + \frac{D\,(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k-g}$$

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. MR. O'DONNELL, DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Absolutely. Utility investors tend to be individuals or institutions interested in current income. The average stock investor interested in income will use the DCF to calculate how much funds he/she will receive relative to the initial investment, which is defined as the current dividend yield and the amount of funds that the investor can expect in the future from the growth in the dividend. Both of these components are central to the basic tenet of the DCF model that combines a dividend yield and a growth rate for dividends to derive the overall rate of return.

Q. HAVE YOU USED THE DCF MODEL IN ANALYZING COMMON STOCKS FOR INVESTMENT PURPOSES?

A. Yes. I have used and continue to use the DCF method extensively in analyzing common stocks for potential personal purchases as well as for purchases contemplated for money management clients that I have served.

Although the DCF formula stated above may appear complicated, the DCF method is intuitively a very simple model to understand. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield which he or she expects to receive in the future to the expected growth in dividends over time. If the regulatory authority sets the rate at a fair level, the utility will be able to attract capital at a reasonable cost, without forcing the utility's customers to pay more than necessary to attract needed capital.

Unlike models such as the CAPM that are more theoretical and academic in nature, the DCF is grounded in solid practicality that is used by money managers and individual investors throughout the world on a daily basis.

Q. CAN YOU GIVE AN EXAMPLE?

A. Yes. If investors expect a current dividend yield of 5%, and also expect that dividends will grow at 4%, then the DCF model indicates that investors would buy the utility's common stock if it provided a return on equity of 9%.

Q. HAVE YOU PREPARED ANY ANALYSES USING THE DCF METHOD TO EVALUATE A FAIR RATE OF RETURN FOR DUKE?

A. Yes. To start, it is important to recognize that Duke is a wholly owned subsidiary of Duke Energy Corporation and, as such, there is no publicly traded stock of Duke. However, by itself, Duke is the single largest subsidiary of Duke Energy Corporation and, as such, Duke Energy Corporation is a good proxy for the market required return of Duke.

At the present time, Duke Energy Corporation is in the midst of a merger with Progress Energy Corporation. As a result, investors must consider the long-term rate of return prospects of Duke as well as the short-term ramifications of the merger with Progress Energy. To isolate any possible risk/return variations associated with the merger I prepared a DCF analysis of companies comparable to Duke that included some companies that were involved in merger activity and then another comparable group where I deleted those companies involved in merger activities

The first comparable group that examined all companies comparable to Duke Energy Corporation, including those that are involved in merger activities, can be found in Exhibit KWO-1. The second comparable group that deleted companies involved mergers is found in Exhibit KWO-2, I developed these two groups of comparable companies to ensure that the return on equity for Duke developed in this analysis is consistent with the returns which can be obtained from similar equity investments in the open market.

Q. DO YOU AGREE WITH MR. HEVERT THAT ONE SHOULD NOT PREPARE A DCF ANALYSIS FOR DUKE SINCE THE PARENT UTILITY IS IN THE MIDST OF A MERGER WITH PROGRESS ENERGY CORPORATION?

A. No. The point of this rate case is to set rates for Duke, which is the largest subsidiary of Duke Energy Corporation. Without a risk/return assessment of Duke, the Commission has no point of reference. I will admit, however, that it is possible that some of Duke's price movement over the past year has been due to possible merger activity. In fact, in the table below, you can see that Duke has outperformed its utility counterparts over the past year.

Table 1: Duke Energy Corporation Stock Price Relative to Peers

	1 Month	6 Months	12 Months
Duke Energy Corporation	+1.9%	+10.4%	+14.0%
Electric UtilitiesSub-Industry	+0.6%	+7.4%	+6.3%
Electric UtilitiesIndustry	+0.6%	+7.4%	+6.3%

	1 Month	6 Months	12 Months
Utilities Sector	+0.3%	+6.2%	+6.7%

Datasource: Standard & Poor's
All performance periods are based on trailing daily prices.
Source for table: www.charlesschwab.com

The manner in which the analyst compensates for this price movement due, possibly, to merger activity is to adjust the chosen rate of return within the DCF range and to explain why the adjustment was made. However, in my view, simply ignoring the company altogether does not give the Commission a full view of the risk/return parameters on which they must make a decision.

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES FOR YOUR TWO COMPARABLE GROUPS.

A. All of the companies in my two comparable groups are listed in The Value Line Investment Survey "Electric Utility Industry" group.

A further screen I used in developing my comparable group of companies was to include only those companies in the comparable group that have an S&P Quality Rating of a B, which is the quality rating for Duke Energy Corporation, or a B+, the next highest quality rating. This quality rating is an appropriate screening method because the S&P Quality Rating measures stability of earnings and dividends.

For both comparable groups, I also chose to exclude companies that either paid no dividend or had recently reinstated or reduced their dividends.

As stated above, the first comparable group, as found in Exhibit KWO-1, included companies that are involved in merger activities whereas the second comparable group, as found in Exhibit KWO-2, excluded companies involved in merger activities.

Q. HAVE YOU PREPARED ANY ANALYSES USING THE DCF METHOD TO EVALUATE A FAIR RATE OF RETURN FOR DUKE?

A. Yes, I have. First, I identified the current dividend yields and projected growth for both comparable companies.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each comparable company, as reported by the Value Line Investment Survey. To study the short-term as well as long-term movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for the comparable group. The period covered for this analysis is from July 29, 2011 through October 21, 2011. My results appear in Exhibit No. KWO-1 and KWO-2 and show a dividend yield of 4.4% over these three time periods for the first comparable group, which included companies involved in merger activity, and 4.4% to 4.5% for the second comparable group, which excluded companies involved in merger activity. Over this same time period, the Duke-only dividend yield ranged from 5.1% to 5.3%.

Q PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE?

A. I developed the dividend yield range for the comparable group by averaging each Company's dividend yield over the above-stated 13-week and 4-week periods as well as examining the most recent dividend yield reported by Value Line for each company.

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE?

A. I used several methods in determining the growth in dividends that investors expect including the "plowback ratio" method, and analyzing historical and forecasted compound annual rates of change using different industry tools.

Q. PLEASE DESCRIBE THE "PLOWBACK RATIO" METHOD.

A. If a company is earning a rate of return (r) on its common equity, and it retains a percentage of these earnings (b), then each year the earnings per share (EPS) are expected to increase by the product (br) of its earnings per share in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% (the other 50% being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (50% of 10%). To calculate a plowback for the comparable group, I used the following formula:

$$g = \frac{br\ (2010) + br\ (2011E) + br\ (2012E) + br\ (14E\text{-}16E\ Avg)}{4}$$

The plowback estimates for all companies in the comparable group can be obtained from The Value Line Investment Survey under the title "percent retained to common equity." Exhibit No. KWO-3 lists the plowback ratios for each company in the comparable group that included companies with merger activity Exhibit No. KWO-4 lists the plowback ratios for each company in the comparable group that excluded companies with merger activity. These exhibits contains reference to "NMF" which is the abbreviation for "no meaningful figure". When "NMF" appears, a company's earnings were less than the dividend paid out, which means that the Company did not reinvest or "plowback" any earnings from that year's operations. For purposes of being conservative, I treated the "NMF" entries as a 0 for purposes of my analysis. The plowback method is a very useful tool for comparing the comparable group's growth rates on a recent historical basis as well as a short-term forecasted basis.

Q. ARE OTHER FACTORS IMPORTANT IN THIS ANALYSIS?

A. Yes. A key component in the DCF Method is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Method, the analyst must consider how dividends are created. Since dividends cannot be paid out without the company first earning the funds paid out, earnings growth is a key element in analyzing the expected growth in dividends. Similarly, what remains in a company after it pays its dividend is reinvested, or "plowed back", into the company in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a company's expected dividend growth. To analyze the expected growth in dividends, I believe the analyst should first examine the historical record of past earnings, dividends, and book value.

Q. DID YOU CONDUCT SUCH AN ANALYSIS?

A. Yes, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported by Value Line.

Value Line is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor examines all aspects of a Company's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates for the company for which the analysis is being performed. The historical growth rates for the comparable group can be seen in O'Donnell Exhibit No. KWO-1 and KWO-2.

Q. DID YOU CONDUCT ANY OTHER ANALYSES?

A. Yes. The third method I used was the Value Line forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share. And the fourth method I used was the forecasted rate of change for earnings per share that analysts supplied to Charles Schwab & Co. This forecasted rate of change is not a forecast supplied by Charles Schwab & Co. but is, instead, a compilation of forecasts by industry analysts.

Q. WHERE CAN YOUR RESULTS BE FOUND?

The details of my DCF results can be seen in Exhibit No. KWO-1 and KWO-2.

Once I gathered all the above data, I examined the results as found in Exhibit Nos. KWO-1 and KWO-2. It is important, in my view, to attempt to understand the reasons why the various data results appear. For example, in the early 1980s, utilities were undergoing expansion of base load plants that caused earnings growth to slow substantially. However, in the early 1990s, most baseload plant construction had ended and utilities were flush with a good bit of cash thereby creating, for the most part, solid earnings growth. Today, many utilities, such as Duke Energy Corporation, are currently building generation plants in anticipation of future earnings growth once the utility puts these plant investments into rate base.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS?

A. As can be seen on Exhibit KWO-1, the dividend yield for the three time frames studied is a consistent 4.4% for the first comparable group and4.4% to 4.5% for the second comparable group, and 5.1% to 5.3% for Duke. It is my preference to recommend returns on equity within 25 basis parameters so, for purposes of this analysis, I believe the proper dividend yield to use in the DCF analysis is in the range of 4.25% to 4.75% for the two comparable groups. 4.25% is slightly below the low-end dividend yield of 4.4% for the first comparable group whereas 4.75%

is slightly above the high-end 4.5% dividend yield of the second comparable group. For Duke, my recommended dividend yield range is 5.0% to 5.5%. 5.0% is below the low-end (5.1%) dividend yield range for Duke whereas 5.5% is just above the 5.3% high dividend yield for Duke.

In terms of the proper dividend growth rate to employ in this analysis, I believe that it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. An examination of the 10-year and 5-year historical growth rates for both comparable groups vividly shows the problems in the electric industry over the past decade.

Q. PLEASE EXPLAIN.

A. The future of the utility industry can, in my opinion, be described as "back to the future" in which utilities will expand their earnings by expanding and growing their rate base investments through large capital projects. Throughout the 1990s and 2000s, it was rare to see a general rate case for any utility in the United States. Today, however, utilities across the country are coming in for rate cases at an increasing pace. The future holds much the same as numerous large power plant investments are currently being planned.

Q. HOW DOES THIS IMPACT THE ANALYSIS?

A. Due to the effects of fundamental changes that have occurred in the utility industry over the past ten years, I believe that it is proper to place more weight on forecasted figures than historical figures in estimating the cost of equity for the comparable group. As a result, I believe that the proper growth rate range for the two comparable groups of companies to use in the DCF analysis is 4.5% to 5.0%. This growth rate range recognizes that most electric utilities will be undergoing plant expansions in the near term and simply cannot be expected to grow their dividends at the same pace of earnings growth. Thus, the 4.5% to 5.0% growth rate range is higher than forecasted dividend and book value growth but yet slightly less than forecasted earnings growth for the two comparable groups.

Combining the comparable group's dividend yield of 4.25% to 4.75% with the growth rate range of 4.5% to 5.0% produces a DCF range of 8.75% to 9.75%.

For Duke, as can be seen in Exhibits KWO-1 and KWO-2, I believe the proper growth rate range is in the range of 3.75% to 4.25%. The lower end of the range is slightly below the forecasted earnings growth but yet still much higher than dividend and book value forecasted growth of Duke as shown in Exhibit KWO-1. I believe 4.5% is appropriate for the upper end of the range because it recognizes Duke is in the midst of a large construction campaign where the utility will be adding plant to rate base thereby driving up earnings growth once the plant construction has been completed.

Since the DCF formula is predicated on future dividend growth, it would be, as stated above, inaccurate to use only earnings growth rates in the DCF. Doing so produces unrealistically high return on equity numbers that cannot be sustained in real life. To mitigate this problem, I have presented EPS, DPS, and BPS figures to the Commission and systematically explained my rationale for arriving at the above stated growth rates. I believe it is incumbent upon every analyst presenting testimony in this case to present such a robust analysis to the Commission.

Combining Duke's dividend yield range of 5.0% to 5.5% with the growth rate range of 3.75% to 4.25% produces a DCF range of 8.75% to 9.75%.

The above-stated comparable group cost of equity range represents only one analysis I used in the examination of the proper cost of equity to apply in the current rate case.

B. Comparable Earnings Analysis

Q. MR. O'DONNELL, WOULD YOU PLEASE EXPLAIN WHY YOU PERFORMED A COMPARABLE EARNINGS ANALYSIS IN ADDITION TO YOUR DCF ANALYSIS?

A. Yes. The comparable earnings method provides investors with actual historical earned returns on common equity. Investors use this information as a guide to assess an investment's current required rate of return. I used the comparable earnings method in my analysis in this case to assess the reasonableness of my DCF results and to provide an independent methodological estimate of the return that investors would consider reasonable for Duke.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS?

A. O'Donnell Exhibit Nos. KWO-5 present a list of the earned returns over the period of 2010 through the forecasted period up to 2016 for the comparable group that included companies with merger activity. Exhibit KWO-6 shows the earned return on equity over this same time period for the comparable group that excluded companies with merger activity. As can be seen in these exhibits, the comparable groups' average earned returns on equity was approximately 9.0% in 2010 but the forecasted return on equity is expected to rise to between 9.6% (no merger activity) to 9.7% (merger activity) through 2016. As demonstrated by the forecasted growth rates shown in my DCF analysis, Duke is not expected to grow as much as the comparable groups. In 2010, Duke posted a return on equity of 7.8% but its forecasted return on equity going out to 2016 is not expected to rise above 8.5%.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPARABLE EARNINGS ANALYSIS?

A. Based on the above-stated findings, I believe the proper rate of return using a comparable earnings analysis is in the range of 8.5% to 9.5%. The 8.5% lower end of the range is equal to the forecasted earned return on equity of Duke for the period of 2014 through 2016. The 9.5% return on equity for the high end of the range is slightly lower than the forecasted return of the comparable group in this same 2014-2016 forecasted time period. This rate of return range of 8.5% to 9.5% is very close to the return on equity range found appropriate through use of the DCF model.

C. Return on Equity Recommendation

Q. WHAT IS YOUR RECOMMENDATION FOR THE RETURN ON EQUITY AND OVERALL RATE OF RETURN THE COMMISSION SHOULD USE IN THIS PROCEEDING?

A. As I mentioned earlier, the results from my DCF Analysis resulted in an investor return requirement range of 8.75% to 9.75% for both comparable groups and Duke.

The comparable earnings method produces a return on equity in the range of 8.5% to 9.5%. My specific recommendation in this case is for the Commission to grant Duke a return on equity of 9.5%. This 9.5% ROE is in the middle-to-high end of the range of the DCF results for the comparable group and Duke; and is in the high-end of the range for the comparable earnings analysis.

It is important for the Commission to remember that the United States is enduring a period of very tough economic circumstances. Interest rates are at historic lows due to recent easing in US monetary policy; housing prices plummeted in the mid-2000s and still have not returned; United States debt and local government debt is at historic levels; unemployment is high; consumer spending is depressed; European balance sheets are hemorrhaging red ink; business investment is depressed; and the stock market, at best, is moving sideways. All of these factors point to a long period, perhaps as much as 10-years, of sub-standard returns on common equity for utilities and all other types of investment.

Q. HOW DOES YOUR RECOMMENDED RETURN ON EQUITY COMPARE TO RECOMMENDATIONS FROM OTHER WITNESSES ACROSS THE COUNTRY?

A. Other rate of return witnesses across the United State have also recognized the current period of historical low expected rates of return in the marketplace. On Sept. 2, 2011 in the general rate case of Nevada Power, the staff witness for the PUC recommended a 9.4% return on equity and a 7.82% overall rate of return. In that same case, the Office of the Nevada Attorney General Bureau of Consumer Protection recommended a 9.7% return on equity and a 7.95% overall rate of return. In North Carolina, Public Staff witness Ben Johnson filed testimony in Duke's North Carolina rate case and recommended a return on equity of 9.25%.

Q. DO YOU HAVE ANY OTHER COMPARISON TO SHOW THE REASONABLENESS OF YOUR RECOMMENDATION IN THIS PROCEEDING?

A. Yes. In a data request to the Company, I asked the Company to provide the assumed equity rate of return Duke is using in its retirement portfolio for calculating its pension expense. While Duke did not provide the actual assumed rate of return I requested, it did provide the weighted rate of return for its equity investments portion of its retirement portfolio. Based on this data request, I have calculated Duke's assumed return on equity for its pension expense to be 8.5%.

In this case, Duke is asking the Commission to base its pension expense calculations on an 8.5% return on equity but, on the other hand, it is asking the Commission to award its stockholders a return on equity of 11.5%. The two divergent returns on equity simply do not make sense. Either Duke has assumed a low return on equity for its pension portfolio and, thereby, over-calculated its pension expense requirements OR the utility has inflated its return on equity request in this rate case. Simply put, Duke cannot have it both ways. South Carolina consumers cannot support a pension portfolio expected to underperform while, at the same time, support a return on equity plant investment well above market required returns on equity.

Q. HOW DO YOU BELIEVE DUKE WILL RESPOND TO YOUR ARGUMENT THAT THE RETURN ON EQUITY ASSUMED FOR THE COMPANY'S PENSION PLAN ASSETS IS IN CONFLICT WITH DUKE'S REQUESTED RETURN ON EQUITY IN THIS CASE?

A. I expect Mr. Hevert will claim that the pension return is an <u>expected</u> rate of return whereas the 11.5% requested by Duke in this case is a <u>required</u> rate of return. I also expect Mr. Hevert will claim that the portfolio of Duke's pension assets is different from the investment characteristics of Duke. However, I counter that the pension investments are typically more risky, and thereby deserve a higher return, than an investment in a regulated utility. Hence, the divergence between expected (Duke's pension assets) and required (Duke's requested return) rates of return is simply illogical.

D. Capital Structure

Q. MR. O'DONNELL, HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT IS A CAPITAL STRUCTURE AND HOW WILL IT IMPACT THE REVENUES THAT DUKE ENERGY CORPORATION OR ANY OTHER UTILITY IS SEEKING IN A RATE CASE?

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments.

For simplicity purposes, there are basically three financing methods. The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity returns, which take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 40% more expensive than debt financing. The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible. Corporate debt is the other major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in less than one-year. Both long-term debt and short-term debt represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books by the cost rates associated with each form of capital and then summing the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Since the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to a pre-tax returns by grossing up the common equity and preferred stock returns for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for its return on investment and tax payments associated with that investment.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. From the above discussion, it is clear to see that costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. However, long-term debt, which is first in-line for repayment, is more risky to the utility than is common equity due to the fact that debt is a contractual obligation as opposed to common equity where no similar obligations exist.

Q. WHY SHOULD THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION BE CONCERNED ABOUT HOW DUKE FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how Duke finances its rate base investment. The first reason is that the cost of common equity is higher than the cost of long-term debt, so that a higher equity percentage will translate into higher costs to Duke's customers with no corresponding improvements in quality of service. Long-term debt is a financial promise made by the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the nature of this investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a promissory note from the company.

The second reason the Commission should be concerned about Duke's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as Duke Energy Corporation, can write-off interest payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. Since the regulatory process allows utilities to recover all expenses, including taxes, rates must be set so that the utility pays all its taxes and has enough left over to pay its common stock dividend. If a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to pay the associated income tax burden, resulting in unfairly, unreasonably, and unnecessarily high rates. This will harm the economy of the utility's service area and violate the fundamental principles of utility regulation that rates must be fair but only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. MR. O'DONNELL, WHAT CAPITAL STRUCTURE IS DUKE SEEKING IN THIS CASE?

A. According to the testimony of Ms. Carol Shrum, the Company is seeking approval of the following Duke capital structure in this case:

Long-Term Debt	47.0%
Common Equity	53.0%

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. I will not argue with the actual percentages of equity and debt proposed by Duke in this proceeding, but I am concerned with the use of the Duke capital structure in future proceedings

Q. WHAT CONCERNS YOU ABOUT THE USE OF THE DUKE CAPITAL STRUCTURE?

A. Duke is a wholly-owned subsidiary of Duke Energy Corporation. Due to the parent/subsidiary relationship, there are no market forces that influence the shape of the Duke capital structure. As a result, Duke Energy Corporation can issue long-term debt on its consolidated balance sheet and then invest the funds into Duke and call it common equity. By doing so, Duke Energy Corporation can effectively create whatever capital structure it desires for Duke and its other subsidiaries. My specific ongoing concern is that Duke Energy Corporation can choose to increase the equity ratio of Duke well past the current equity ratio of 53%. If that situation occurs, rates will increase unnecessarily to captive customers.

Q. WHAT ARE THE POTENTIAL IMPACTS OF USING A SUBSIDIARY CAPITAL STRUCTURE IN SETTING RATES FOR A REGULATED UTILITY?

A. In this case, Duke Energy Corporation is the sole upstream owner of Duke. In some cases, such as in the Northern States Power in which I recently testified, I found that the parent company was attempting to use the regulatory process to force captive customers to pay rates higher than is necessary to support the Company's rate base investment. In utility regulation, a parent company's use of long-term debt as common equity in a regulated subsidiary is called double-leverage.

On the unregulated side, there is no real problem with this practice because the unregulated subsidiaries are subject to competitive market discipline, but on the regulated side – i.e., for Duke and its customers – this practice is a wholly inappropriate manipulation of the claimed capital structure to effectively arbitrage what is debt investment into equity returns, and the Commission should reject and prohibit such manipulation.

Q. WHY DO YOU RECOMMEND THE COMMISSION CAP DUKE'S CAPITAL STRUCTURE AT AN EQUITY RATIO OF 53%?

A. As noted above, a higher equity ratio translates into higher rates to consumers. In the table below, I have prepared a summary of the increase in revenue requirements that will occur with higher equity ratios for Duke.

Table 2: Change in Revenue Requirements Due to Change in Equity Ratio

Duke Equity Ratio	50.00%	55.00%	60.00%	65.00%
Pre-Tax Net Income Req. (000s)	$513,266	$541,754	$570,243	$598,731
Increase in Rev. Req. (000s)	------	$28,488	$56,977	$85,465

As can be seen in this table, revenue requirements for Duke in South Carolina will increase by about $28.5 million per year when the equity ratio moves upward 5%. My recommendation of a cap of 53% equity ratio gives Duke sufficient strength to maintain is A credit rating while, at the same time, does not expose ratepayers to higher rates through an equity thick capital structure.

Q. WHY WOULD DUKE PREFER TO SET RATES BASED ON A HIGHER EQUITY RATIO?

A. There are two answers to this question. First, if Duke Energy Corporation issues debt to the marketplace and infuses that debt into Duke as common equity, it can actually earn much more on this debt investment than its allowed return on equity.

Consider the following situation: Duke Energy Corporation issues debt at a rate of 5% and then invests those debt proceeds into a regulated subsidiary, Duke as common equity. In this case, Duke Energy Corporation pays the bondholder 5% interest but it receives 11.5% (Duke's requested return in this case). In this example, Duke Energy Corporation can immediately double (5% to 11.5%) the return on its debt investment by essentially re-categorizing debt as equity. This debt-to-equity situation gets even more attractive to the utility when one considers that revenues for the utility must be increased to pay for the tax payments required for the utility to earn the 11.5% rate of return. When these tax payments are included, the pre-tax rate of return on equity investments rises to approximately 19%. Hence, in this example, Duke Energy Corporation can more than triple its return on its debt issuance by turning the debt at the holding company level into common equity at the regulated subsidiary level.

Q. **WHAT IS THE OVERALL RATE OF RETURN ON INVESTMENT THAT THE COMMISSION SHOULD APPLY USING YOUR RECOMMENDED RATE OF RETURN ON EQUITY AND YOUR RECOMMENDED ADJUSTMENTS TO DUKE's CAPITAL STRUCTURE?**

A. As can be seen in Exhibit KWO-7, my recommended overall rate of return on investment is 7.58%.

E. Review of Testimony of Company Witness Hevert

Q. WHAT METHODS DID MR. HEVERT USE IN HIS ANALYSIS OF THE COST OF EQUITY FOR XCEL?

A. Mr. Hevert used the DCF model and the Capital Asset Pricing Model (CAPM), which is essentially a risk premium model, in his analysis.

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND MR. HEVERT'S APPLICATION OF THE DCF?

A. One difference between Mr. Hevert and myself is that Mr. Hevert uses forecasted earnings growth estimates as the primary source of dividend growth in the DCF model whereas I use a more global approach that examines historical and forecasted growth in earnings, dividends, and book value. In my opinion, investors are competent enough to understand that dividend growth, which is the basis for the DCF model, originates from earnings growth and book value growth. Hence, it is only logical to examine all of these factors in the determination of the proper growth rate to use in the DCF model. By doing so, it is logical to understand that such a range will include high growth rates and low growth rates. Investors use all this information in determining the price at which they are willing to pay for the stock and, hence, the underlying investor return requirement using the DCF model.

By focusing only on forecasted earnings growth, Mr. Hevert has mistakenly skewed his results upward. A quick examination of the earnings, dividends, and book value historical and forecasted growth rates will reveal that Mr. Hevert advocates only the highest growth rates in the DCF model thereby producing unrealistically high return on equity estimates.

Q. MR. O'DONNELL, WHY DO YOU NOT USE THE CAPM IN DETERMINING RETURNS ON EQUITY IN UTILITY REGULATORY PROCEEDINGS?

A. I have two primary concerns regarding the CAPM's application in setting expected returns on equity. The first concern deals with the assumption in the CAPM that assumes that calculated risk premiums stay relatively constant over time. I have found such assumptions to be unrealistic. The second concern is that the beta in the CAPM is incapable of capturing sudden changes in risk.

Q. PLEASE EXPLAIN YOUR CONCERN REGARDING THE RISK PREMIUM EMPLOYED IN THE CAPM.

A. Current economic conditions are vastly different from conditions that existed in the marketplace since 1926, which is the start date of the risk premium analysis used by Mr. Hevert. For example, from the end of WWII until the mid-1990s, the United States economy was generally seen as the dominant market in the world. Today, however, China and India are all making strong economic strides that are threatening our dominance in world markets. Mr. Hevert's risk premium model, by definition and specification, ignores the changing world markets.

In 2004, Dr. Jeremy J. Siegel from the University of Pennsylvania published a paper for the Chartered Financial Analysts Institute Conference Proceedings entitled "The Long-Run Equity Risk Premium." In this study, Dr. Siegel examined stock and bond market return returns from 1802 through 2003. Over this extended period of time, the real return on common stocks was 6.8% whereas the real return on long-term government bonds was 3.5% thereby producing a risk-premium of 3.3%. The summary of the article states:

> This is a lower return world because the P/E for equities is justifiably higher than it has been historically, which implies lower long-term real equity returns. Siegel's constant of a 6.5-7 percent return equity returns problem will not hold for all future periods.

> Investors probably will receive closer to 5 percent. Nevertheless, the real equity risk premium will still be roughly 3 percent. Investors will certainly seek other higher yielding real assets, but of the three major asset classes – stocks, bonds, and real estate – all are probably going to realize lower return than their historical averages. Consequently, equities still offer an attractive premium for long-term investors.

Also in 2004, Mr. Robert D. Arnott, editor of the Financial Analysts Journal, wrote an article entitled "The Meaning of a Slender Risk Premium." Mr. Arnott concluded his piece by stating that

> The risk premium rules of thumb we've relied on are shaky. Indeed, the risk premium is a skinny hook to hang our future prosperity on. Should we rely on the risk premium for profit, or should we look more aggressively for other paths to profit? I think the latter is by far the more sensible route.

As a financial analyst, the use of a risk premium as high as 7.22% to 8.27% as done by Mr. Hevert is, in my opinion, unjustified given the current world markets. It might make some simplistic sense to pick a period of time over which to study equity risk premiums, but it is imperative that the analyst performing the study consider current market conditions. The world we live in today is vastly different than the world we have experienced over the past 200 years. Ignoring this fact will lead the analyst to erroneous conclusions that, in the current case, will cause consumers in South Carolina to overpay for electric service thereby harming the South Carolina economy.

At the very least, I hope that Mr. Hevert updates his CAPM results at the time of the hearing. Since the Company filed Mr. Hevert's prefiled testimony, the yield on 30-year US Treasury bonds has fallen to approximately 3% whereas, at the time of his prefiled testimony, the yield on 30-year US Treasury bonds was approximately 4.5%. If Mr. Hevert does choose to update his testimony, his

CAPM return should fall below well below his recommended return on equity of 11.5%.

Q. PLEASE EXPLAIN YOUR STATEMENT THAT THE BETA USED IN THE CAPM DOES NOT ADEQUATELY CAPTURE CHANGES IN RISK.

A. The CAPM uses a beta variable to measure the risk of the company studied relative to the market. In my view, this beta is highly subjective and can only be used with the utmost care. Since the beta is calculated with historical returns relative to market returns, it is very possible, and in fact quite likely, that sudden changes in a company's stock price will not be captured in the beta thereby producing meaningless answers. If, for example, the beta used in the analysis was calculated over an extended time period, such as how Value Line calculates its beta, and then a company suddenly encountered severe financial problems, the CAPM would produce meaningless results as the calculated return on equity would be grossly low.

An example of the problem with beta can be seen in the situation involving Countrywide Financial, which was the world's largest independent residential mortgage lender and service company. Countrywide has symbolically become the poster child for the credit meltdown that has now occurred in the marketplace thereby setting off recession worries for the entire country. The August 24, 2007 edition of Value Line states that Countrywide's stock price had fallen 54% since its May, 2007 report. However, even with this price decline, the calculated beta for Countrywide was just 1.15 as of August 24, 2007 meaning that Countrywide was perceived as being only 15% more risky than the overall stock market. Given the precipitous drop of Countrywide and past concerns of a wide credit meltdown resulting in thousands of homeowners losing their houses at that point in time, it is hard to believe that Countrywide's beta was just 1.15. Applying this beta in a CAPM will provide an absurd result.

Lastly, I urge the Commission to consider how each, individually, looks at investments and apply the same reasoning to discerning the validity of the DCF and CAPM models. When a person is contemplating making an investment, that person will consider both the short-term and long-term returns in making that investment. With the DCF, the short-term return is represented by the current dividend yield and the long-term growth return is represented in the growth of expected dividends. As a result, the DCF is a practical "real-life" model that is used by investors throughout the world each and every day. The CAPM, on the other hand, is a pure academic model that depends on an assumed risk premium and risk-free rate to arrive at a return on equity estimation. Investors simply do not use such an academic model in the daily "real life" decisions.

III. Accounting Adjustments

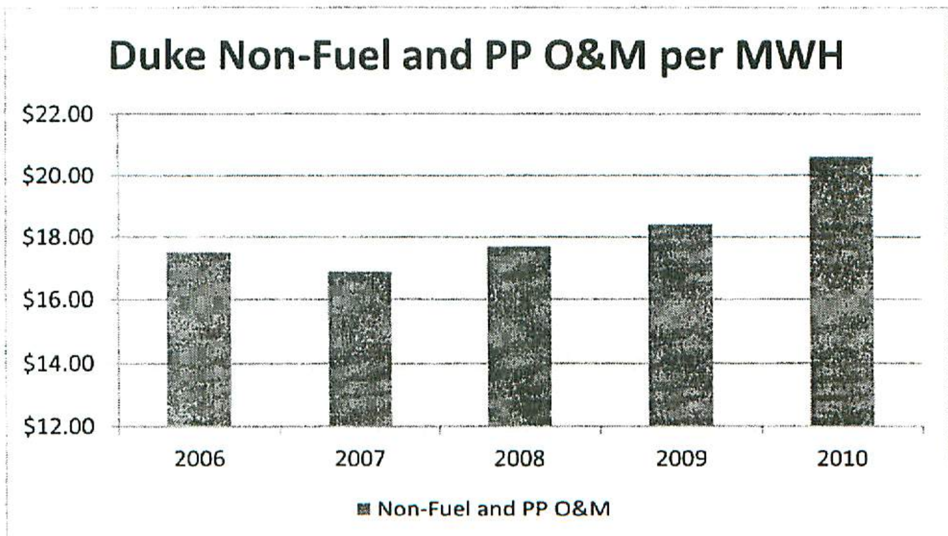
Q. MR. O'DONNELL, HAVE YOU REVIEWED THE COMPANY'S FINANCIAL STATEMENTS AS PRESENTED IN THIS CASE?

A. Yes. I have reviewed Duke's financial statements presented in this case as well as the Duke FERC Form 1 statement from 2006 through 2010.

Q. DO YOU AGREE WITH MS. HEIGL'S STATEMENTS FOUND ON P. 18 OF HER TESTIMONY THAT THE COMPANY'S O&M EXPENSES HAVE BEEN "RELATIVELY FLAT" SINCE THE 2009 RATE CASE?

A. No, I do not. Unfortunately, figures obtained from the FERC Form 1 simply do not support that statement from Ms. Heigl. Below is a chart showing Duke's non-fuel and non-purchased power expenses from 2006 through 2010.

Chart 1: Duke Non-fuel and Non-Purchased Power O&M per MWH



In raw numbers, Duke's O&M expenses less fuel and purchased power expenses increased from $1.56 billion in 2009 to $1.85 billion in 2010. I will grant, however, that a portion of that $290 million increase in O&M expenses was due to the voluntary opportunity plan cost, the one-time pension expense, and other items for which the Company is recovery over a three-year period. In the current case relative to the filed rate case in 2009, Duke's non-fuel and non-purchased power expenses for which it is seeking recovery rose from $750.1 million (Shrum Exhibit 1, p. 1, Docket 2009-226-E) to $885.1 million (Shrum Exhibit 1, p. 1 of current case), which represents an increase of $135 million or 18%.

Given the size of this rate increase request by Duke, I encourage the Commission to pay very close attention to Duke's O&M expenses in the future. As can be seen in the graph above, the trend of Duke's O&M expenses is not favorable for ratepayers in South Carolina.

Q. WHAT ACTIONS CAN THE COMMISSION TAKE IN THE FUTURE TO CONTROL DUKE'S O&M EXPENSES?

A. If, in the future, Duke does not reasonably control its O&M expenses, the Commission can deny those O&M expenses it feels are unreasonable or, possibly, reduce the Company's return on equity to compensate ratepayers for the higher Duke O&M expenses.

Q. ARE YOU HEREIN RECOMMENDING A REDUCTION IN DUKE'S RETURN ON EQUITY FOR THE INCREASE IN NON-FUEL AND NON-PURCHASED POWER O&M EXPENSES?

A. No. The change in Duke's O&M costs from its last rate case to the current rate case is quite worrisome for ratepayers in the South Carolina. However, it is my understanding that the ORS is performing a comprehensive audit of Duke's financial statements. As a result, I reserve the right to make future adjustments in this case based on the audited findings of the ORS in this case.

Q. TO YOUR KNOWLEDGE, HAS ANY STATE REGULATOR RECENTLY COMPLETED AN AUDIT OF DUKE'S FINANCIAL STATEMENTS?

A. Yes, as part of its rate case filing in Duke's North Carolina rate case, the Public Staff of the North Carolina Utilities Commission filed testimony on Nov. 1, 2011 in which it reduced Duke's rate increase request in North Carolina from $638 million to $211 million. Of that total reduction of $427 million the Public Staff made various accounting and growth-related adjustments totaling about $167 million. The sheer size of the accounting and growth-related adjustments made by the Public Staff in Duke's North Carolina rate proceeding indicates that the trend in O&M expenses as noted above is troubling to parties other than myself.

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST FOR ACCELERATED DEPRECIATION EARLY PLANT RETIREMENTS?

A. No. In this case, Duke is seeking accelerated depreciation of $6.5 million associated with the Company's anticipated early retirement of 890 MW of coal generation where, the Company claims, retrofitting the plants with certain emissions controls is cost prohibitive (see Shrum testimony, p. 14 and 15). However, Duke has apparently based its financial decisions on the proposed EPA Clean Air Transport Rule that has yet to be enacted. It is my understanding that the Clean Air Transport Rule is currently being challenged and it is uncertain when or even if the rule will take effect. As a result, I believe it is premature at this point to accelerate depreciation for these plants at this time. My recommendation is that the Commission deny Duke's request for accelerated depreciation in this case. If the challenge to the Clean Air Transport Rule is resolved by the time Duke files its next rate case, the Company is free to ask for accelerated depreciation at that time.

Q. PLEASE EXPLAIN THE VOLUNTARY OPPORTUNITY PLAN (VOP) AND HOW DUKE IS PROPOSING TO HANDLE THAT EXPENSE IN THIS RATE CASE.

A. In an effort to reduce ongoing labor costs, Duke offered buyout packages to its employees. The cost of these buyout packages allocated to South Carolina retail ratepayers was $23.8 million. In this rate case, Duke is proposing to amortize this one-time expense over 3 years.

Q. DO YOU AGREE WITH THIS THREE-YEAR AMORTIZATION PERIOD?

A. No. In my opinion, Duke should amortize this expense over five-years.

Q. PLEASE EXPLAIN WHY YOU RECOMMED A FIVE-YEAR AMORTIZATION PERIOD FOR THESE VOP EXPENSES?

A. In utility ratemaking, three-year amortizations are a general rule of thumb. To my knowledge, Duke does not, on a regular and ongoing basis, offer buyout options to its employees. Given the size of the rate increase requested by Duke in this case and the fact that voluntary opportunity plans are not offered on a regular basis, I believe a five-year amortization period is fair to Duke and its customers.

Q. DO YOU AGREE WITH DUKE'S REQUEST TO SEEK AN ADDITIONAL $28 MILLION IN THIS RATE CASE DUE TO AN INCREASE IN EMPLOYEE BENEFITS?

A. The majority of this increase is associated with medical expenses incurred by the Company. However, a part of the increase is due to an increase in pension costs. I am concerned about this request from Duke as it represents the second time in two years that Duke has sought an increase in revenues associated with its pension costs. In 2010, Duke began a three-year rate rider in South Carolina in which the Company was allowed to recover higher-than-expected pension costs. Now, in

South Carolina, the Company is seeking higher rates, in part, due to another increase in pension costs.

Q, EXPLAIN THE DIFFERENCE BETWEEN A DEFINED BENEFIT PLAN AND A DEFINED CONTRIBUTION PLAN.

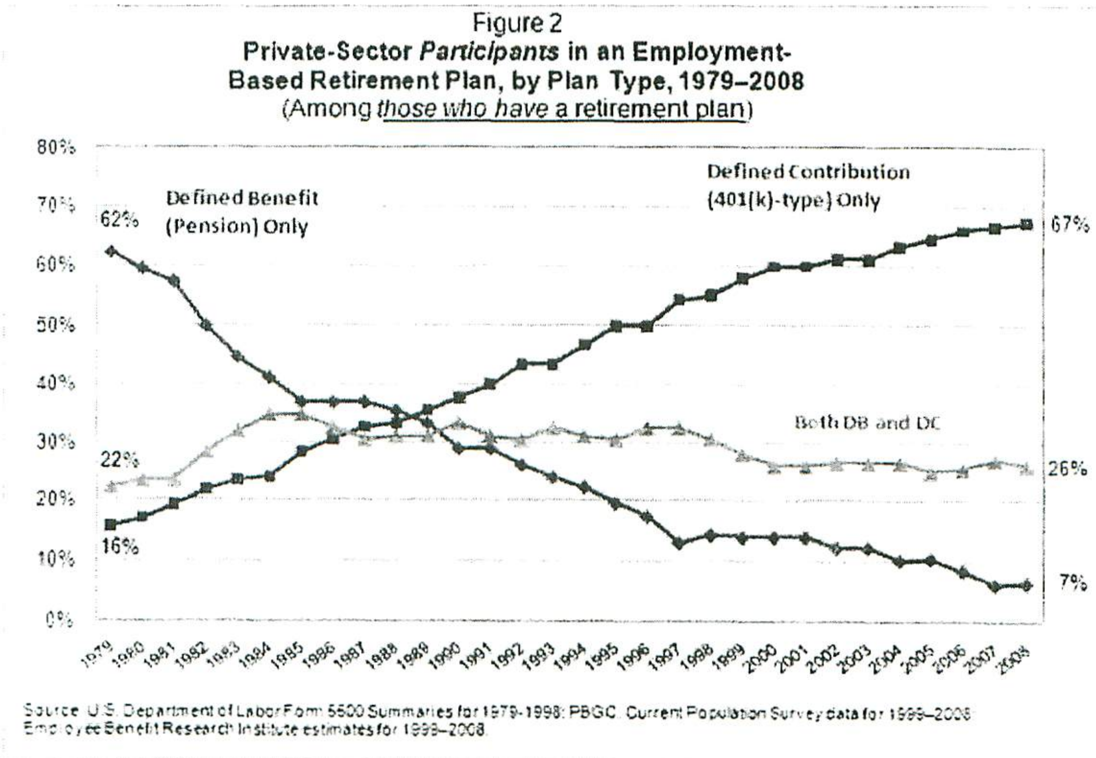
A. A defined benefit plan is one where employees and employers both make a monetary contribution to a fund that will be used to pay out known retirement benefits in the future. With a defined benefit plan, the employer, not the employee, is responsible for making sure that the pension fund is solvent and fully funded.

A defined contribution plan also relies on contributions from employees and employers. However, with a defined contribution plan, the employer is not responsible for making fixed payments in the future. Instead, a defined contribution plan puts the risk on employees to make sure their retirement plan is funded for their own future. In this case, if the employee retirement fund is not growing at a sufficient level to generate the retirement income the employee desires, it is the responsibility of the employee, not the employer, to increase payments to the retirement fund.

Q. PLEASE EXPLAIN WHY YOU BELIEVE DUKE SHOULD MOVE ENTIRELY FROM A DEFINED BENEFIT PROGRAM TO A DEFINED CONTRIBUTION PLAN.

A. Under a traditional defined benefit program, stockholders of the Company are at risk of the pension plan not earning a satisfactory rate of return. To be specific, if the pension plan does not earn the rate of return needed to sustain the pension fund at current contribution levels, stockholders must make up the difference through higher pension contributions, and thereby lower earnings, needed to make the pension fund whole. However, Duke is a regulated utility and, as such, it can ask ratepayers, not stockholders, for increased pension contributions when its defined benefit funds do not earn sufficient rates of return to sustain the fund at current levels. Hence, with Duke, the ratepayers, not the stockholders, are at-risk. Private company employers realized the risk of retirement benefits many years ago and have steadily moved from defined benefit plans to defined contribution plans. In the chart below, this movement in retirement plans is abundantly clear.

Chart 2: Private Sector Retirement Plans



Source for chart: http://www.ebri.org/publications/benfaq/index.cfm?fa=retfaq14

In 2008, only 26% of private-sector employers, including Duke, offered a defined benefit plan combined with a defined contribution plan. 67% of private sector employers, on the other hand, offered only defined contribution plans. Furthermore, in 2008, only 15% of employees working in the private sector were working for firms that offered a defined benefit plan.

At a time of high employment and sagging take-home pay, I don't believe it is appropriate for Duke to ask its ratepayers to pay higher rates to sustain a retirement plan that the vast majority of its customers cannot, themselves, obtain.

Q, HAS DUKE EVER EXAMINED THE POSSIBILITY OF TRANSITIONING ITS EMPLOYEES FROM A DEFINED BENEFIT PLANT TO A DEFINED CONTRIBUTION PLAN?

A. I asked Duke that question in a data request, but the Company evaded the answer. To be specific, the Company stated:

> The Company is committed to maintaining retirement programs designed to ensure that the appropriate type and level of benefits are provided to attract and retain the required caliber of employees. At this time the Company maintains a cash balance pension plan and a defined contribution 401(k) savings plan with the level of benefits designed to be competitive in the industry. Cash balance plans are typically referred to as hybrid pension plans because they incorporate features of defined contribution ("DC") plans. For example, the Duke Cash Balance Plan is defined and communicated as an account balance, similar to a DC plan, that grows with contributions (pay credits) and interest each year. The interest credit rate varies each year.
>
> There are many factors to consider in designing and maintaining appropriate retirement programs. More importantly than the type of program platform (defined benefit or defined contribution) the level of benefits provided and the effect of any transition on current employees would need significant review and consideration. The overall cost of a retirement program (whether it is defined benefit or defined contribution) is driven by the level of benefits provided rather than the platform itself. The platform could influence the incidence of and the volatility of the retirement cost. In addition pensions are one element of the total rewards package where all the compensation and benefit programs need to be considered in aggregate as part of an overall competitive total rewards package.

Q. WHY IS THIS ISSUE OF A DEFINED BENEFIT PLAN SO IMPORTANT IN THE CURRENT PROCEEDING?

A. As noted above in my testimony, Duke's retirement accounts assume an 8.25% total return. An 8.25% return on equity is not sustainable in the long-term. Duke has already admitted in its 2009 rate case that its pension fund suffered "an unusually large reduction in the fair value of pension assets" due to the economic downturn that preceded that rate case. (see settlement stipulation of Nov. 24, 2009 in Docket No. 2009-226-E). The settlement in that case allowed Duke to charge South Carolina ratepayers up to $3.6 million in higher rates due to the decrease in the value of the pension fund. This pension rider was to be adjusted each year since the 2009 rate case. Today, the pension rider is .0089 cents per kWh. For a 10 MW facility with an 85% load factor, this pension rider equals an annual payment of $6,627.

Certainly that Duke will ask for higher rates in its anticipated 2012 rate case should its pension fund not earn its assumed rate of return. If Duke's retirement funds earn less than their assumed rate of return, ratepayers will be continually asked to pay higher and higher rates to sustain Duke's pension fund obligations. This risk of underperforming pension assets is an ongoing concern for many companies that still offer defined benefit funds. In the case of a regulated utility, the ratepayers, not the stockholders, bear the risk of the underperforming pension assets.

The settlement in Duke's 2009 rate case indicated that the issue of the pension rider would be revisited in this rate case.

Q. ARE YOU RECOMMENDING DUKE TERMINATE ITS DEFINED BENEFIT PLAN AS PART OF THIS PROCEEDING?

A. No. Termination of a retirement plan is a decision that should be made by Duke. My recommendation is that ratepayers no longer be "at-risk" of being responsible for times when the investment returns of the pension portfolio do not meet the assumed rate of return for actuarial purposes. In other words, ratepayers should pay a set amount for retirement benefits pensions as if in a defined contribution format, but Duke stockholders should pay the investment return difference if the Company chooses to keep its defined benefit plan. In regard to the pension rider, my recommendation is that the Commission terminate the rider as part of the current rate case. Given the fact that Duke paid out executive bonuses in 2010, I believe they have sufficient resources to shore up their pension fund without having to ask ratepayers to fund the shortcomings of a type of pension plan that the vast majority of South Carolinians cannot themselves afford or benefit from.

Q. PLEASE EXPLAIN THE ONE-TIME PENSION LITIGATION SETTLEMENT THAT DUKE IS REQUESTING RATE RECOVERY FOR IN THIS PROCEEDING.

A. When Duke switched its pension plan obligation in 1997 from a defined benefit plan to a combination of a defined benefit plan and defined contribution plan, employees of Duke sued their employer claiming lost benefits. Duke settled the pension case and, in this case, is attempting to recover from South Carolina ratepayers $7.2 million associated with the settlement of the case.

Q. DO YOU AGREE WITH DUKE'S REQUEST FOR RATEPAYERS TO PAY THE ENTIRE COST OF THIS PENSION LITIGATION EXPENSE?

A. No. When Duke Energy Corporation converted its defined benefit plan in 1997 to a combination of a defined benefit and defined contribution plan, the utility was not in the middle of a large construction project that would soon be followed by large rate cases. The savings that Duke Energy Corporation expected to accrue from this change in the retirement plan would have inevitably flowed to stockholders. Since stockholders benefited from this retirement plan change, I believe it is only fair that stockholders pay the entire cost associated with this pension plan settlement.

In the event the Commission determines to require the ratepayers to pay for some portion of the pension litigation, , I recommend that the portion of the pension litigation expense the Commission assigns to customers be amortized over a five-year amortization period. In light of the executive bonuses paid out last year, I believe it is abundantly fair for stockholders to absorb half of the cost of this litigation expense.

Q. PLEASE SUMMARIZE THE ACCOUNTING ADJUSTMENTS YOU ARE RECOMMENDING IN THIS RATE CASE?

A. The accounting adjustments I am recommending in this rate case are as follows:

- extend amortization period of VOP costs - $3.1 million;
- disallow the accelerated depreciation expense of $6.5 million;
- terminate the pension rider immediately - $3.6 million (from 2009 settlement); and
- disallow the requested $7.2 million in pension litigation expense requested by Duke in this case and amortize the balance over five years.

The above expense adjustments are based on my review of the 2010 Duke FERC Form 1 filing as well as Duke's application in this rate case. Once the ORS' audit of Duke's books is complete and their recommendations are made to the Commission, I may have additional adjustments to make at a later time.

IV. COST OF SERVICE STUDY AND RATE DESIGN

Q. MR. O'DONNELL, WHAT IS A COST OF SERVICE STUDY AND WHY IS IT RELEVANT TO A RISK ANALYSIS?

A. A cost of service study is the starting point for any relative risk analysis. Before any changes are made to customer class rates, the current cost of serving each customer class and the return which the Company earns on service to that class must be determined. Once this information has been determined, customer class rates can be changed in order to bring the resulting class rates of return in line with the risks of serving each class.

Q. IS COST-OF-SERVICE AN IMPORTANT CONSIDERATION WHEN DETERMINING CUSTOMER CLASS REVENUE REQUIREMENTS?

A. Yes. The information received from performing cost-of-service studies is of great importance. In my opinion, the "bottom line" conclusions from a cost-of-service study should be a primary factor in determining customer class revenue requirements.

Q. HOW IS A COST-OF-SERVICE STUDY PERFORMED?

A. The first step in performing a cost of service study is to determine the appropriate test year for which all revenues, expenses, and utility plant investment are based. In the case of Duke, the most recent test year was for the 12 months ending December 31, 2010.

The next step in performing a cost-of-service study is to ascertain the proper level of revenues and expenses to use in this analysis. It is the responsibility of the analyst to ascertain that the revenues and expenses used in the analysis are representative of what the utility can expect on an ongoing basis. Since revenues typically do not vary by a great deal from year-to-year, few adjustments are made in this area. Expenses, on the other hand, can vary considerably so careful consideration must be made with each expense.

Once the revenues and expenses have been adjusted so that they are representative of what the utility reasonably achieved in the test year, the analyst then allocates these revenues and expenses to each of the customer classes. Allocating revenues is a relatively straightforward task since all major utilities, such as Duke, normally retain detailed utility revenue accounts for each customer class. Allocating expenses is, however, more difficult because all the expenses are commonly incurred for providing service to all customers of the electric distribution system. To allocate these expenses, the analyst must use the allocation factors that are based on factors such as annual usage, demand usage, number of customers, etc. Allocating expenses in this manner is normally called "functionalization" of expenses as the process involves arranging the expenses according to major electric utility functions, such as generation, transmission, and distribution.

The allocation of operating expense items requires careful consideration as to how these expenses and investments are incurred and utilized and how best to spread these costs. It is very important that the analyst allocate the given expense by the way such cost is incurred or in the manner in which these expense items are utilized. For purposes of simplicity and example, consider the situation with postage expenses. The vast majority of postage expenses are incurred in sending monthly bills to consumers. Since each consumer gets a bill in the mail, it makes sense to allocate postage expenses by the number of customers in each rate class. Thus for postage expenses, residential customers would bear the largest portion of this expense since that class has the largest number of individual customers.

Operating expenses can be classified into five major groups: production, transmission, distribution, sales, and administrative and general (A&G) expenses.

The method of allocation for each of these four groups will vary as to the way in which these expenses are incurred by the electric utility.

Once the revenues and expenses have been determined by customer class, an income statement is essentially created for each customer class. From this income statement, income taxes can be calculated and then the net income for each customer class is determined.

The next step in the cost-of-service study is to allocate the utility's net plant investment, which is defined as gross plant less depreciation, in a cost-causation manner similar to how the analyst allocated expenses. As was the case with expenses, net plant investment, otherwise known as the rate base, is allocated in the manner in which the utility incurs the cost. There are three major types of utility plant investment that require allocation: generation, transmission, and distribution. Of these types of investment, generation investment is generally the largest investment. As the largest investment, allocation of generation is critically important in the calculation of the cost of service to each customer class.

The last step in the cost-of-service study is to divide the net income for each customer class by the rate base for each class to derive the rate of return earned on service for each customer class. The resulting percentage (%) rate of return for each customer class provides the analyst with a gauge of the profitability of service to each customer class.

Q. WHAT DO THE RESULTS OF THE COST-OF-SERVICE STUDY TELL THE ANALYST PERFORMING THE COST-OF-SERVICE STUDY?

A. If a customer class rate of return is negative, the utility is earning less than the cost of providing service to that class. In that case, the analyst must consider raising rates to that customer class in order to bring the return on service to that class commensurate with the risk of providing that service. If, on the other hand, the utility is earning a return on a customer class far greater than the Company's overall rate of return, the analyst should consider reducing rates in order to lower that customer class rate of return.

Q. SHOULD AN ANALYST LOOK AT FACTORS OTHER THAN CUSTOMER CLASS RATES OF RETURN WHEN EXAMINING HOW TO ADJUST RATES?

A. Yes. The analyst should also consider the how the particular rate increase may impact the service territory of the utility and the long-term impact of the rate change. For example, a rate increase to a manufacturing customer on the verge of financial collapse may well be the last straw that pushes the employer out of the state or, worse, totally out of business. When that manufacturer closes its door, the load of that customer is probably gone forever meaning that rates for all other customers must concurrently increase to keep the utility whole.

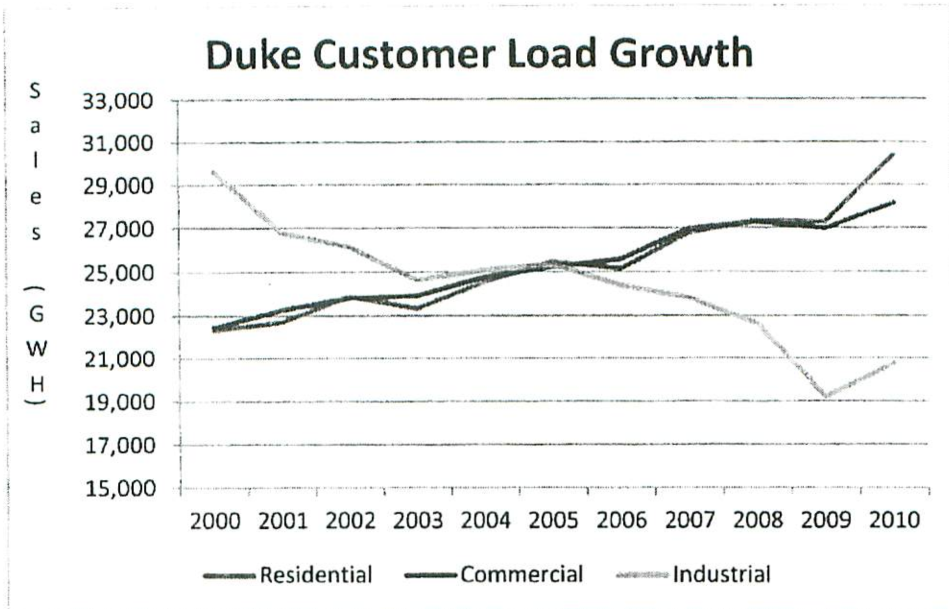
Q. PLEASE EXPLAIN WHY RATES FOR OTHER CLASSES MUST GO UP WHEN AN INDUSTRIAL CUSTOMER CLOSES ITS DOORS.

A. According to the testimony of Duke Witness Shrum, Duke needs total revenues in South Carolina of $1,733,161,000 to earn its requested rate of return of 8.63%. If an industrial customer closes its facility in South Carolina, remaining customers will need to pick up the revenue difference, less the incremental cost of power required to serve that industrial customer.

Q. HOW HAS DUKE'S LOAD CHANGED OVER THE PAST DECADE?

A. Duke's load has continued to grow over the past ten years, but its customer mix has shifted. As can be seen in the chart below, Duke's residential and commercial load has grown, but its industrial load has shrunk.

Chart 3: Duke's Historical Peak Load Growth



Based on the graph above, Duke has lost about 1/3 of its industrial sales over the past 11 years. Needless to say, this current rate increase request will only hurt Duke's efforts to sustain industrial sales in its service territory. As stated above, the loss of industrial sales hurts all remaining consumers, particularly residential consumers, as there are fewer customers left on the system to pay fixed costs.

Q. WHAT IS DUKE FORECASTING FOR FUTURE LOAD GROWTH IN EACH OF ITS SECTORS?

A. According to the Duke's Integrated Resource Plan (IRP), from 2010 through 2013, Duke expects to realize a load growth of 1.3% for residential consumers; 2.0% for commercial consumers; and 0.3% for textile industrial consumers. (p. 106 of 2010 IRP).

It is clear from this forecast and from the historical results over the past ten years that Duke's growth has, and will so in the future, come from residential and commercial sectors and not from the industrial sector.

Q. HAVE YOU EXAMINED THE COST-OF-SERVICE STUDY FILED BY DUKE IN THIS RATE CASE?

A. Yes, I have. I analyzed the coincident peak cost-of-service study a filed by Mr. Phillip O. Stillman as part of his testimony in this proceeding.

Q. WHAT IS A "COINCIDENT PEAK" COST-OF-SERVICE STUDY?

A. As stated above, the most critical part of a cost-of-service study for an electric utility is the method in which generation investment is allocated. This one allocation, more so than any other, will have the greatest influence on the resulting customer class rates of return. Since Duke is a summer peaking utility, Mr. Stillman allocated the Company's generation investment to all customer classes by a ratio of each class's peak demand relative to the entire Duke peak demand.

Q. DO YOU AGREE WITH COMPANY WITNESS STILLMAN'S TESTIMONY THAT USE OF THE COINCIDENT PEAK ALLOCATION METHODOLOGY IS APPROPRATE FOR USE IN THIS CASE?

A. Yes. Since Duke builds generating plant to meet the peak demand on its system, it make sense to allocate generation investment by the coincident peak ratio.

Q. DOES THE COINCIDENT PEAK METHOD REFLECT THE MANNER IN WHICH DUKE'S CUSTOMERS USE ELECTRICITY?

A. Yes. Duke has three major customer classes: residential, commercial, and industrial. Of these three classes, the residential class is the most temperature-sensitive and time-sensitive class. Put simply, when the temperature rises outside the home, residential consumers respond by running their air conditioners more frequently. The time at which residential consumers use the most electricity is, typically, the late afternoon hours of a hot summer day when workers come home from work. To accommodate the need for electricity, Duke must ramp up its more expensive generating plants to meet this summer peak demand.

Industrial consumers, on the other hand, keep their energy consumption relatively level as these customers are much less sensitive to temperature fluctuations than are residential consumers. Furthermore, it is often very costly for a large manufacturer to ramp up and down its manufacturing operations due to the stresses that such variations place on manufacturing equipment.

Q. WHY IS RATE DESIGN SO CRITICAL TO DUKE CONSUMERS IN THIS RATE CASE?

A. Duke is currently in the midst of a large construction cycle. In the current rate case, Duke is bringing costs associated with three new generation plants into rate base. In the years ahead, it is expected that Duke will bring even more costs into rate base as the utility, perhaps, builds a nuclear plant. If properly designed, Duke's rates can be designed so as to change customer behavior so that future construction projects can be delayed and perhaps even cancelled outright.

Q. DOES THE RATE DESIGN PROPOSED BY DUKE IN THIS CASE ENCOURAGE CUSTOMERS TO CHANGE THEIR BEHAVIOR SO AS TO ASSIST THE COMPANY AVOID FUTURE LARGE CONSTRUCTION PROJECTS?

A. No. The existing rate design offered by Duke does not effectively incent customers to reduce their on-peak usage. In my opinion, the Company should offer rate designs that recognize and reward customers that demonstrate an ability to reduce peak load usage for the benefit of all customers.

Q. PLEASE PROVIDE SOME RATE DESIGN CONCEPTS THAT BENEFIT CUSTOMERS THAT REDUCE THEIR PEAK DEMAND WHILE, AT THE SAME TIME, ASSIST UTILITIES IN CONTROLLING THEIR OWN COSTS.

A. A quick review of the recent integrated resource plan (IRP) of Duke shows that both utilities have significant plans to increase their plant investment in service to customers. For example, in this rate case filing, Duke is bringing into rates its investment in the Cliffside coal plant as well as the Buck and Dan River natural gas plants.

Generation portfolios are generally built to meet the peak needs of the consuming public. As such, SCEUC is asking Duke for rate designs that will help the utilities reduce the need to build additional base load generation. Below are some additional rate design concepts that will help Duke and its customer base delay the need to build additional generation in the future:

- Coincident peak (CP) rates that incent manufacturers not to consume electricity at the time of the system peak;
- An increase in interruptible credits that reflect the cost of incremental constructed generation; and,
- More economical time-of-use rates to tie in with the energy efficiency programs of Duke.

The goal in each of these types of rates is to allow consumers to assist in controlling utility costs while, at the same time, help consumers control their own power costs.

Q. DO COINCIDENT PEAK RATES EXIST IN TODAY'S MARKETPLACE?

A. Yes. In fact, coincident peak (CP) rates exist right now in the Carolinas. In Appendix B are copies of a CP rate for manufacturers located in Gastonia, North

Carolina, which is a member of the North Carolina Municipal Power Agency No. 1 (NCMPA1). As can be seen from this rate, there is a very effective economic incentive to help the supplying utility shave its peak in an effort to shave costs.

Q. HOW DO THESE CP RATES COMPARE TO EXISTING RATES OF DUKE?

A. CP rates can be very advantageous to consumers that are willing to shave load at the time of the utility's peak. Below is an example of annual power costs from a large customer located in the territories of Duke and Gastonia.

Table 3

Power Bill Example for a Large, North Carolina Customer

Utility	Rate	$ Cost	$/kWh
Duke	OPT-I	$2,480,359	$0.05899
Gastonia	08-4C	$1,606,984	$0.03822

Assumptions: 7,000 kW on-peak
6,000 kW off-peak
80% load factor
35% on-peak energy
65% off-peak energy

In the table above, the manufacturer in Gastonia would be able to take its plant off-line at the of Duke's monthly peak. As can be seen by employing Gastonia's annual cost would save the manufacturer close to $900,000. The manufacturer looking to optimize the benefits of the CP rate must be willing to shave its load roughly 20-30 hours per month. However, as can be seen above, the economic benefits of such a CP rate design are quite substantial.

Q. OTHER THAN BENEFITTING THEIR CUSTOMERS, IS THERE ANOTHER REASON WHY DUKE SHOULD BE INTERESTED IN OFFERING CP RATES TO THEIR CUSTOMERS?

A. Yes. As can be seen in Table 3 above, a large customer that can shed load at the time of the monthly coincident peak can save substantial costs taking power supply services from Gastonia as opposed to Duke. In fact, the figures in the above table did not include the current rate increase request of 14% made by Duke, nor do these figures include Duke's expected requests for rate increases next year. Relative to Gastonia, Duke's rates are becoming uncompetitive. Given the fact that Duke's earnings have suffered recently due, in part, to the loss of industrial load, it would make good business sense for Duke to work hard at producing rates that would encourage economic development in their territory so that it is competitive with Gastonia and other NCMPA1 cities.

Q. HOW CAN CP RATES HELP INVESTOR-OWNED UTILITIES, SUCH AS DUKE, CONTROL THEIR OWN POWER COSTS?

A. CP rates incent large customers to reduce their load at the time of the utility peak. In the case of Duke, as cited above, the reduction of on-peak load can help Duke delay the need for expensive generation in the future. If enough consumers are incented to reduce their on-peak load, Duke may be able to delay the need for future generation. Such a result would be a huge victory for all consumers as it would delay the need for future rate increases to pay for very expensive base load (nuclear or coal) or peaking/intermediate natural gas-fired units. This savings would be shared by ALL customers and keep the Carolinas competitive.

Q. CAN CP RATES BE DESIGNED IF THERE IS NO HISTORICAL DATA TO SHOW HOW CUSTOMERS WILL REACT TO THE INTRODUCTION OF THESE RATES?

A. Yes, the analyst performing the analysis must make reasonable forecasts on how large industrial consumers will react to the introduction of CP rates. To be specific, the rate analyst can assume that Duke's peak load is cut by 50 MW, for example, as a result of this new CP rate. From that point, expenses can be aligned with the new lower cost to serve customers that take service on a CP rate. CP rates can then be calculated to produce revenues needed to meet the cost of service plus a reasonable rate of return.

Q. WHY CAN THE ANALYST NOT USE EXISTING COST OF SERVICE STUDIES TO DESIGN CP RATES?

A. Existing cost of service studies are based on historical results and, as such, cannot capture forward-looking effects that CP rates can have on a utility's cost structure. Adjustments to expenses in existing cost of service studies must be made in order to account for the beneficial effects of a CP rate.

Q. WHY WOULD A REGULATED UTILITY OPPOSE CP RATES THAT HELP LOWER THEIR COSTS?

A. Under the current regulatory paradigm, regulated utilities increase their earnings by building plant and equipment and placing those assets in rate base on which they earn a profit. Without an increase in the rate base, is becomes more difficult for the regulated utility to increase its profits. Hence, in the regulated world, an increase in the rate base is an earnings driver. Unfortunately, plant addition to the rate base also involves increasing rates to consumers, as witnessed by Duke's current rate case filing. Duke's requested 15% rate increase is painful for consumers to absorb, particularly given the poor economy coupled with high unemployment.

However, to Duke's credit, it appears that Duke SC President Catherine Heigel understands the economic realities of the world in which we now operate. In her pre-filed testimony in this rate case filing, Ms. Heigel states:

> We believe strongly that a healthy industrial base is good for all of our customers. A healthy and broad industrial customer base enables us to spread our fixed costs over a broader group of customers, thereby ensuring that prices are lower, on average, for all customers.

These statements suggest a desire by Duke to chart a better course for its industrial customers.

The rate proposals discussed in my testimony represent tangible and significant steps that help manufacturers in South Carolina survive these tough economic times so that, hopefully, Duke's sales volume trajectory reverses course and increases in the future.

Q. HAVE YOU DISCUSSED THE COINCIDENT PEAK RATE DESIGN CONCEPT WITH ANYONE AT DUKE?

A. Yes. As is noted on p. 27 of Mr. Bailey's prefiled testimony, in its final order from the 2009 rate case, the Commission directed Duke to discuss rate design concepts with interested parties. I have had two discussions with Mr. Bailey on CP rates, but it is my understanding that the Company is not yet willing to embrace the CP rate design concept. Given that Duke has lost almost 1/3 of its industrial sales over the past 11 years and, through this rate case, is seeking to increase industrial rates by 12% in this case, logic dictates that the Company should do all in its power to develop new rates that will encourage greater industrial use while at the same time promote reduced peak load usage.

Q. DO YOU BELIEVE THE COMMISSION SHOULD REQUIRE DUKE TO OFFER THESE TYPES OF RATE DESIGNS AS PART OF THIS RATE CASE?

A. Yes. Duke is in the process of completing a huge capital investment project associated with the Buck, Dan River, and Cliffside generating units. In the future, it is possible the Company will build, or participate in the building, of a nuclear plant. All of these construction projects involve large capital investments. To avoid future rate shocks to customers, the Commission should take the current opportunity to encourage and mandate Duke to offer customers adequate incentives to cut the utility's peak costs and delay future rate increases.

Without this Duke rate increase request, the Commission would not have the opportunity for customers to propose rate alternatives that can benefit customers and utilities alike. Without specific regulatory or legislative mandates for rate alternatives, South Carolina's ratepayers will continue to be hamstrung by the limitations of the current rate offerings for the foreseeable future.

Q. HOW CAN HIGHER INTERRUPTIBLE CREDITS OFFERED BY DUKE HELP THE COMPANY LOWER ITS OWN COSTS?

A. As noted above, Duke has a need to build expensive new generation in the next decade. At the present time, Duke offers only varying credits for interruptible power as can be seen in Rider PSC (Powershare Call Option Nonresidential Load Curtailment). In this rider, Duke provides varying credits to customers based on the maximum number of times that the Company can interrupt the customer. For example, option PS-10/5 would allow Duke to interrupt the large customer 10 times in the summer months for "economy" reasons with 5 maximum annual emergency events. Under the "economy" interruptions, Duke can interrupt the customer and take the interrupted load and sell that capacity into the secondary market where it can earn a premium over the regulated price it would otherwise receive from its retail consumers. For the PS-10/5 option, Duke will pay consumers $2.08 per kW for the capacity to be interrupted and 4.5 cents per kWh for the usage during the time of the interruption. Under this plan, a customer with 2000 kW of interruptible load that is interrupted can receive annual capacity credits from Duke of $49,920. If the length of each interruption is 4 hours per occurrence, the customer can also earn an additional \$5,400 for a total annual credit of \$55,320.

As an alternative, the capacity-based credit for interruptibility could be based on the avoided cost of constructing additional generation or, if the utility has excess capacity, the price at which the utility is able to sell the excess capacity in the open market. Given that Duke continues to claim a need for new-build generation, the appropriate credit is more likely to take the form of avoided cost rather than market value. Duke already has an avoided cost tariff on file with the Commission, so this tariff can be used as a basis for the interruptible demand response rates.

Q. CAN YOU PLEASE PROVIDE A NUMERICAL EXAMPLE OF HOW THE CURRENT DUKE AVOIDED COST RATE WILL WORK WITH INTERRUPTIBLE LOADS?

A. Yes. Duke's current avoided cost rate is Schedule PP. This rate schedule contains an on-peak and an off-peak capacity payment as well as an on-peak energy payment and an off-peak energy payment. There are two different contract terms (variable and 5-years) with prices increasing for the longer the generator can produce power or, in this example, the large customer is willing to interrupt its power supply service. In essence, the longer the customer is willing to interrupt, the greater its rate credit.

If a large customer is, for example, connected at the distribution level and chose to interrupt its load and get paid via Schedule PP, it could choose the variable rate that would pay the customer 2.41 cents per kWh for on-peak capacity and 5.13 cents per kWh for avoided on-peak energy. A customer with a 2,000 kW load that can interrupt its on-peak load for 250 hours per year can earn as much as \$94,250 through this interruption. It is important to note that under the current Rate Schedule PP, the time at which the customer operates is at its discretion.

Similarly, an interruptible rate based on Schedule PP would similarly allow the customer the discretion of interrupting its own load. Hence, this option would be deemed an economic demand response program in that the customer chooses to employ its own economic rationale to decide when to interrupt power supplies.

The above savings may provide enough of an incentive for a customer to change the production shifts of a facility such that employees come into work at varying times in order to take advantage of the savings available by this interruptible rider. By changing the plant production profile, the manufacturer is actually helping Duke and all its other customers control the peak load of the utility and, thereby, avoid the future need of additional plant investment.

Q. DO YOU AGREE WITH MR. BAILEY'S PROPOSAL TO OFFER A NEW TRANSFORMATION DISCOUNT TO BE AVAILABLE TO NEW CUSTOMERS ON SCHEDULES OPT?

A. I appreciate Dukes willingness to improve economic development prospects, but the decision to offer the transformation discount only to new customers harms existing Duke customers.

Q. WHY IS DUKE NOT WILLING TO OFFER THIS DISCOUNT TO EXISTING CUSTOMERS?

A. On p. 14 of his prefiled testimony, Mr. Bailey states that there is not sufficient information on which to distinguish customers based on voltage. He further states that, in his opinion, it would be unfair to offer this new rate since, historically, large customers were not incented to own transformation equipment. Since the customers would not own the transformation equipment, they would not qualify for the transformation discount.

Q. DO YOU AGREE THAT EXISTING CUSTOMERS SHOULD NOT BE OFFERED THE TRANSFORMATION DISCOUNT?

A. No. Mr. Bailey's argument implies that Duke refuses to offer existing customers the substations needed to take delivery at the higher 115-kV or lower voltage levels. As part of this rate case, Duke should be required to offer to sell this transformation equipment at net book values (original price less depreciated value) and then offer these customers the same transformation discount Duke is now proposing to offer new customers. Doing otherwise would be discriminatory to existing customers.

It is easier to keep an existing customer than to create a new customer. Duke's request to offer the transformation discount only to new customers should be amended so that the discount is applicable to all customers.

Q. DO YOU AGREE WITH THE PROPOSED CHANGES TO RATE SCHEDULE MP?

A. No, I do not. In its initial filing, Duke proposed an increase in Schedule MP rates that was approximately <u>double</u> the rate increase that commercial and industrial consumers will experience. To make the situation worse for Schedule MP customers, the Company did not provide any testimony to support a rate increase that doubled what other customers in this case will realize.

Table 4 below provides the basic increase originally sought by Duke in this proceeding. As one can easily see, Duke's requested increase was heavily loaded on the demand side that will translate into an approximate increase of 25% per customer.

Table 4
Duke
Schedule MP
2011 Rate Case Rate Impact

	% Increase over Current Rates	
	Transmission	Distribution.
Basic Facility Chg	7.2%	7.2%
Demand Chg.		
On-Peak Demand		
Trans.	53.1%	53.1%
Dist.	53.1%	53.1%
Excess Demand	28.2%	28.2%
Energy		
On-Peak	11.3%	11.7%
Off-Peak	-2.6%	-1.9%

In its application in this case, Duke did not explain the rationale for this large rate increase. Duke's rate design witness, Mr. Jeff Bailey, simply provided the existing Schedule MP tariff and the same Schedule MP tariff after the proposed rate increase. The customers were left to determine the rate increase requested by Duke as there was no testimony explaining the drastic rate increase.

Q. HAS DUKE FILED UPDATED TESTIMONY IN REGARD TO SCHEDULE MP?

A. Yes. Duke Witness Bailey filed supplemental testimony on Nov. 11, 2011 and acknowledged a mistake in the original Schedule MP calculations. However, Mr. Bailey, again, only provided the proposed Schedule MP rate with no explanation as to how this rate was calculated nor the impact the new rate would have on customers. Table 5 below shows the impact to each of the Schedule MP rates based on the updated testimony of Mr. Bailey.

Table 5
Duke Schedule MP
2011 Rate Case Rate Impact

		Increase over Current Rates	
		Trans.	Dist.
Basic Facility Chg		12.2%	12.2%
Demand Chg.			
On-Peak Demand			
	Trans.	27.8%	27.8%
	Dist.	27.8%	27.8%
	Excess Demand	28.2%	28.2%
Energy			
	On-Peak	11.3%	11.8%
	Off-Peak	-2.6%	-1.9%

As can be seen in Table 5 above, the increase now proposed by Mr. Bailey is still quite substantial. Unfortunately, Mr. Bailey, even in the supplemental testimony, does not provide the overall rate increase proposed by Schedule MP customers nor does he provide any justification for the rate change to this group of customers. Until such time as Duke provides evidence to the Commission to justify the rate change, I believe the Commission has no choice but to deny Duke's request to change the Schedule MP rates.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION IMPLEMENT THE RATE INCREASE FROM THIS RATE CASE?

A. I believe that it is critical that the Commission require Duke to phase-in this rate increase over two years. In the current case, Duke is seeking a 15% rate increase, which translates into an additional $215.5 million in additional annual revenues. Based on my analysis in this rate case, I believe the Commission should cut Duke's request to no more than $121.8 million, which is a 8.5% overall annual rate increase. This recommendation is, however, contingent upon my final review of the audit results of the ORS that will be filed at the same time as this testimony.

Given the current poor economic conditions and high unemployment rate in South Carolina, an 8.5% rate increase is very difficult to absorb. This sizable rate increase is even more difficult when one considers that Duke customers have also just absorbed a fuel increase from the Company that raised residential rates 5.5%, commercial rates by 7%, and industrial rates by 10%. Needless to say a near-20% rate hike will severely impact the South Carolina manufacturing industry at a time when the state's unemployment rate is already very high. Duke should welcome my recommendation to phase-in new rates so that its earnings do not suffer due to customers cutting usage in response to this large base rate increase combined with the recent fuel rate increase.

V. SUMMARY

Q. MR. O'DONNELL, PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. The Company's requested return on equity of 11.5% is excessive and punitive to consumers in South Carolina.

I performed my cost of equity analysis using the DCF model as well as the comparable earnings model. My conclusion is that 9.50% is the proper return on equity to grant Duke in this proceeding.

In evaluating the Company's requested capital structure, I believe the proper capital structure to employ for ratemaking purpose is a hypothetical capital structure of 53% common equity and 47% long-term debt.

Combining my recommended return on equity of 9.50% with the Dec. 31, 2010 capital structure will produce my final overall rate of return recommendation of 7.58%.

I recommend the Commission deny Duke's request to recover accelerated depreciation expenses of $6.5 million related to anticipated early plant retirements.

Duke is proposing to amortize its VOP expenses over 3-years that, in my opinion, should be amortized over 5-years so as to minimize the rate impact of this rate case.

Duke's request for ratepayers to pay for pension litigation expense should be disallowed.

I recommend that the Commission require Duke to develop coincident peak (CP) rates as part of this rate case. A CP rate can be economical to manufacturers as well as serve to delay the need for additional generation plant by Duke. This type of "win-win" scenario is very attractive given the size of this rate case.

Duke should also be required to offer more economical time-of-use rates so that customers will be incented to use less power on peak thereby lessening the need for additional generation construction.

Duke should open its transformation discount to ALL customers and not just new customers.

The rate increase for MP customers should be no more than the overall rate increase for the customer class on which the customer would be served were it not for the existence of the MP rate.

Duke's rate change for Schedule MP is not supported by evidence in the record and should be disallowed.

The rate increases from this rate case should be phased in over a period of at least two years.

Q. **DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, it does.

Duke Energy

Docket No. 2011-271-E

Comparable Group Merger Activity

	DCF Results														
	13 Wk Avg. Dividend Yield	4 Wk Avg. Dividend Yield	Current Dividend Yield	Value Line										Plowback Growth Rate	Schwab Forecasted EPS
				10 Year			5 Year			Forecasted					
Company				EPS	DPS	BPS	EPS	DPS	BPS	EPS	DPS	BPS			
ALLETE	4.6%	4.8%	4.8%	—	--	–	3.5%	17.5%	5.0%	4.5%	2.0%	3.0%		2.8%	6.0%
Alliant Energy	4.4%	4.5%	4.6%	3.0%	-3.5%	1.0%	9.0%	0.5%	3.5%	7.0%	6.0%	3.0%		4.1%	6.0%
Amer. Elec. Power	5.0%	5.0%	5.0%	2.5%	-3.5%	1.0%	2.0%	2.0%	5.0%	4.5%	4.0%	4.5%		4.3%	4.2%
Ameren Corp.	5.3%	5.2%	5.1%	-0.5%	-3.0%	3.5%	-1.5%	-6.0%	2.5%	-2.0%	-3.0%	1.5%		2.8%	3.0%
Black Hills	4.9%	4.8%	4.7%	-3.0%	3.0%	10.0%	-6.0%	2.5%	4.5%	8.5%	1.5%	2.0%		1.7%	6.0%
Cen. Vermont Pub. Serv.	2.6%	2.6%	2.6%	6.5%	0.5%	2.0%	12.5%	0.5%	2.0%	2.0%	1.5%	3.0%		3.5%	N/A
CenterPoint Energy	4.1%	4.1%	4.2%	–	–	–	5.0%	13.5%	8.5%	3.0%	3.0%	10.0%		4.0%	5.9%
CH Energy Group	4.0%	4.1%	4.1%	-1.0%	–	1.5%	-1.0%	–	1.5%	4.0%	0.5%	2.0%		2.4%	N/A
Cleco Corp.	3.3%	3.4%	3.4%	4.5%	1.0%	7.5%	7.5%	0.5%	11.0%	6.0%	9.5%	6.5%		5.2%	3.0%
CMS Energy Corp.	4.6%	4.5%	4.5%	-7.5%	-9.5%	-6.0%	17.5%	–	1.5%	7.0%	14.0%	5.0%		5.7%	6.0%
Consol. Edison	4.4%	4.2%	4.2%	1.0%	1.0%	3.5%	4.0%	1.0%	4.5%	3.0%	1.0%	2.5%		3.2%	3.9%
Constellation Energy	2.5%	2.5%	2.5%	-5.0%	-2.5%	5.0%	-16.0%	1.5%	4.5%	18.0%	-4.0%	6.5%		3.6%	7.0%
DTE Energy	4.8%	4.8%	4.9%	–	0.5%	3.5%	2.5%	1.0%	3.5%	4.5%	4.0%	3.5%		3.4%	3.6%
Edison Int'l	3.5%	3.5%	3.4%	–	2.5%	9.5%	10.0%	15.5%	10.5%	-1.0%	2.0%	5.0%		5.0%	3.0%
Exelon Corp.	4.9%	4.9%	4.9%	9.5%	–	5.0%	8.0%	10.5%	6.5%	-1.5%	nil	5.5%		6.8%	1.0%
G't Plains Energy	4.4%	4.3%	4.1%	-3.5%	-4.0%	4.0%	-11.5%	-8.0%	7.0%	6.0%	nil	2.0%		2.7%	5.9%
Hawaiian Elec.	5.2%	5.2%	5.1%	-2.5%	–	2.0%	-6.0%	–	1.0%	11.0%	1.0%	3.0%		2.0%	7.0%
IDACORP, Inc.	3.1%	3.2%	3.2%	-0.5%	-4.5%	3.5%	11.0%	-2.5%	4.5%	4.0%	4.0%	5.0%		5.1%	4.7%
Integrys Energy	5.5%	5.6%	5.5%	1.0%	3.0%	7.0%	-8.0%	4.0%	5.5%	9.0%	nil	1.5%		2.2%	7.2%
MGE Energy	3.7%	3.7%	3.7%	4.5%	1.0%	6.5%	7.0%	1.5%	6.5%	4.0%	2.0%	4.0%		4.5%	4.0%
Northeast Utilities	3.4%	3.4%	3.4%	–	19.0%	2.5%	13.5%	8.0%	2.5%	7.5%	7.0%	6.0%		5.3%	7.3%
NV Energy	3.7%	3.5%	3.5%	3.5%	-10.5%	-2.5%	–	–	3.0%	9.5%	11.0%	4.0%		3.7%	10.1%
Otter Tail Corp.	5.8%	6.1%	6.1%	-1.0%	2.0%	7.0%	-5.5%	2.0%	6.5%	13.0%	1.5%	1.5%		0.5%	5.0%
Pepco Holdings	5.7%	5.7%	5.7%	-0.5%	–	0.5%	-0.5%	1.5%	1.0%	2.5%	1.0%	2.0%		1.3%	3.3%
PG&E Corp.	4.4%	4.4%	4.2%	–	3.5%	5.5%	7.0%	–	10.5%	6.0%	4.5%	5.5%		4.4%	5.2%
Pinnacle West Capital	4.9%	4.9%	4.9%	-2.5%	4.5%	2.5%	0.5%	3.0%	0.5%	6.0%	1.5%	2.5%		2.9%	6.5%
PNM Resources	3.3%	3.3%	3.0%	-9.5%	--	2.5%	-18.0%	-4.5%	–	19.5%	7.0%	3.0%		2.3%	8.2%
Progress Energy	5.2%	5.0%	4.8%	1.5%	2.0%	4.0%	-1.0%	1.5%	1.5%	3.5%	1.0%	3.5%		1.7%	4.0%
Public Serv. Enterprise	4.2%	4.1%	4.0%	6.5%	2.0%	5.5%	12.0%	4.0%	7.5%	1.0%	1.5%	7.5%		7.0%	3.3%
SCANA Corp.	5.0%	5.0%	4.9%	4.5%	3.5%	4.0%	2.0%	5.0%	4.5%	3.0%	2.0%	5.0%		3.7%	4.5%
TECO Energy	4.8%	5.0%	5.1%	-5.5%	-4.5%	-1.5%	12.0%	-0.5%	5.0%	10.5%	4.5%	5.0%		4.7%	6.1%
UIL Holdings	5.3%	5.3%	5.3%	-1.0%	–	–	7.5%	–	-2.0%	3.0%	nil	5.5%		1.6%	4.0%
Vectren Corp.	5.2%	5.2%	5.1%	1.5%	3.5%	4.0%	2.5%	3.5%	4.0%	5.5%	3.0%	3.5%		2.3%	5.6%
Westar Energy	5.0%	5.0%	4.9%	–	-4.5%	-3.0%	1.0%	7.0%	6.0%	8.5%	3.0%	2.0%		2.8%	6.0%
Xcel Energy Inc.	4.4%	4.3%	4.2%	-1.0%	-4.0%	–	4.0%	4.0%	4.0%	5.0%	3.0%	5.0%		4.2%	5.3%
	4.4%	4.4%	4.4%	0.2%	-0.1%	3.3%	2.5%	3.1%	4.5%	5.9%	3.2%	4.0%		3.5%	5.2%
Duke Energy	5.3%	5.2%	5.1%	–	–	--	--	--	–	5.5%	2.0%	2.5%		2.5%	4.0%

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011. Charles Schwab & Co. Reports as of Sept. 28, 2011.

Exhibit KWO-1

Duke Energy

Docket No. 2011-271-E

Comparable Group No Merger Activity

	DCF Results														
				Value Line										Plowback	Schwab
	13 Wk. Avg.	4 Wk. Avg.	Current	10 Year			5 Year			Forecasted				Growth	Forecasted
Company	Dividend Yield	Dividend Yield	Dividend Yield	EPS	DPS	BPS	EPS	DPS	BPS	EPS	DPS	BPS		Rate	EPS
ALLETE	4.6%	4.8%	4.8%	---	--	--	3.5%	17.5%	5.0%	4.5%	2.0%	3.0%		2.8%	6.0%
Alliant Energy	4.4%	4.5%	4.6%	3.0%	-3.5%	1.0%	9.0%	0.5%	3.5%	7.0%	6.0%	3.0%		4.1%	6.0%
Amer. Elec. Power	5.0%	5.0%	5.0%	2.5%	-3.5%	1.0%	2.0%	2.0%	5.0%	4.5%	4.0%	4.5%		4.3%	4.2%
Ameren Corp.	5.3%	5.2%	5.1%	-0.5%	-3.0%	3.5%	-1.5%	-6.0%	2.5%	-2.0%	-3.0%	1.5%		2.8%	3.0%
Black Hills	4.9%	4.8%	4.7%	-3.0%	3.0%	10.0%	-6.0%	2.5%	4.5%	8.5%	1.5%	2.0%		1.7%	6.0%
Cen. Vermont Pub. Serv.	2.6%	2.6%	2.6%	6.5%	0.5%	2.0%	12.5%	0.5%	2.0%	2.0%	1.5%	3.0%		3.5%	N/A
CenterPoint Energy	4.1%	4.1%	4.2%	--	--	--	5.0%	13.5%	8.5%	3.0%	3.0%	10.0%		4.0%	5.9%
CH Energy Group	4.0%	4.1%	4.1%	-1.0%	--	1.5%	-1.0%	--	1.5%	4.0%	0.5%	2.0%		2.4%	N/A
Cleco Corp.	3.3%	3.4%	3.4%	4.5%	1.0%	7.5%	7.5%	0.5%	11.0%	6.0%	9.5%	6.5%		5.2%	3.0%
CMS Energy Corp.	4.6%	4.5%	4.5%	-7.5%	-9.5%	-6.0%	17.5%	--	1.5%	7.0%	14.0%	5.0%		5.7%	6.0%
Consol. Edison	4.4%	4.2%	4.2%	1.0%	1.0%	3.5%	4.0%	1.0%	4.5%	3.0%	1.0%	2.5%		3.2%	3.9%
DTE Energy	4.8%	4.8%	4.9%	--	0.5%	3.5%	2.5%	1.0%	3.5%	4.5%	4.0%	3.5%		3.4%	3.6%
Edison Int'l	3.5%	3.5%	3.4%	--	2.5%	9.5%	10.0%	15.5%	10.5%	-1.0%	2.0%	5.0%		5.0%	3.0%
G't Plains Energy	4.4%	4.3%	4.1%	-3.5%	-4.0%	4.0%	-11.5%	-8.0%	7.0%	6.0%	nil	2.0%		2.7%	5.9%
Hawaiian Elec.	5.2%	5.2%	5.1%	-2.5%	--	2.0%	-6.0%	--	1.0%	11.0%	1.0%	3.0%		2.0%	7.0%
IDACORP, Inc.	3.1%	3.2%	3.2%	-0.5%	-4.5%	3.5%	11.0%	-2.5%	4.5%	4.0%	4.0%	5.0%		5.1%	4.7%
Integrys Energy	5.5%	5.6%	5.5%	1.0%	3.0%	7.0%	-8.0%	4.0%	5.5%	9.0%	nil	1.5%		2.2%	7.2%
MGE Energy	3.7%	3.7%	3.7%	4.5%	1.0%	6.5%	7.0%	1.5%	6.5%	4.0%	2.0%	4.0%		4.5%	4.0%
NV Energy	3.7%	3.5%	3.5%	3.5%	-10.5%	-2.5%	--	--	3.0%	9.5%	11.0%	4.0%		3.7%	10.1%
Otter Tail Corp.	5.8%	6.1%	6.1%	-1.0%	2.0%	7.0%	-5.5%	2.0%	6.5%	13.0%	1.5%	1.5%		0.5%	5.0%
Pepco Holdings	5.7%	5.7%	5.7%	-0.5%	--	0.5%	-0.5%	1.5%	1.0%	2.5%	1.0%	2.0%		1.3%	3.3%
PG&E Corp.	4.4%	4.4%	4.2%	--	3.5%	5.5%	7.0%	--	10.5%	6.0%	4.5%	5.5%		4.4%	5.2%
Pinnacle West Capital	4.9%	4.9%	4.9%	-2.5%	4.5%	2.5%	0.5%	3.0%	0.5%	6.0%	1.5%	2.5%		2.9%	6.5%
PNM Resources	3.3%	3.3%	3.0%	-9.5%	--	2.5%	-18.0%	-4.5%	--	19.5%	7.0%	3.0%		2.3%	8.2%
Public Serv. Enterprise	4.2%	4.1%	4.0%	6.5%	2.0%	5.5%	12.0%	4.0%	7.5%	1.0%	1.5%	7.5%		7.0%	3.3%
SCANA Corp.	5.0%	5.0%	4.9%	4.5%	3.5%	4.0%	2.0%	5.0%	4.5%	3.0%	2.0%	5.0%		3.7%	4.5%
TECO Energy	4.8%	5.0%	5.1%	-5.5%	-4.5%	-1.5%	12.0%	-0.5%	5.0%	10.5%	4.5%	5.0%		4.7%	6.1%
UIL Holdings	5.3%	5.3%	5.3%	-1.0%	--	--	7.5%	--	-2.0%	3.0%	nil	5.5%		1.6%	4.0%
Vectren Corp.	5.2%	5.2%	5.1%	1.5%	3.5%	4.0%	2.5%	3.5%	4.0%	5.5%	3.0%	3.5%		2.3%	5.6%
Westar Energy	5.0%	5.0%	4.9%	--	-4.5%	-3.0%	1.0%	7.0%	6.0%	8.5%	3.0%	2.0%		2.8%	6.0%
Xcel Energy Inc.	4.4%	4.3%	4.2%	-1.0%	-4.0%	--	4.0%	4.0%	4.0%	5.0%	3.0%	5.0%		4.2%	5.3%
	4.5%	**4.5%**	**4.5%**	**0.0%**	**-0.8%**	**3.1%**	**2.7%**	**2.7%**	**4.6%**	**5.7%**	**3.4%**	**3.8%**		**3.4%**	**5.3%**
Duke Energy	**5.3%**	**5.2%**	**5.1%**	**--**	**--**	**--**	**--**	**--**	**--**	**5.5%**	**2.0%**	**2.5%**		**2.5%**	**4.0%**

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011. Charles Schwab & Co. Reports as of Sept. 28, 2011.

Exhibit KWO-2

Duke Energy

Docket No. 2011-271-E

Comparable Group Includes Companies with Merger Activity

Company	% Retained to Common Equity 2010	2011E	2012E	14-16E	Average
ALLETE	1.5%	3.0%	3.0%	3.5%	2.8%
Alliant Energy	3.8%	4.0%	4.0%	4.5%	4.1%
Amer. Elec. Power	3.1%	4.5%	4.5%	5.0%	4.3%
Ameren Corp.	3.8%	2.5%	2.5%	2.5%	2.8%
Black Hills	0.7%	1.5%	2.0%	2.5%	1.7%
Cen. Vermont Pub. Serv.	3.4%	3.5%	3.5%	3.5%	3.5%
CenterPoint Energy	3.8%	4.0%	4.0%	4.0%	4.0%
CH Energy Group	2.2%	2.5%	2.0%	3.0%	2.4%
Cleco Corp.	6.1%	5.5%	5.0%	4.0%	5.2%
CMS Energy Corp.	6.9%	5.5%	5.5%	5.0%	5.7%
Consol. Edison	3.3%	3.0%	3.0%	3.5%	3.2%
Constellation Energy	1.8%	3.5%	3.5%	5.5%	3.6%
DTE Energy	4.0%	3.0%	3.0%	3.5%	3.4%
Edison Int'l	6.5%	4.5%	4.5%	4.5%	5.0%
Exelon Corp.	8.7%	8.0%	3.5%	7.0%	6.8%
G't Plains Energy	3.4%	2.0%	2.5%	3.0%	2.7%
Hawaiian Elec.	1.4%	1.0%	1.5%	4.0%	2.0%
IDACORP, Inc.	5.5%	5.0%	5.5%	4.5%	5.1%
Integrys Energy	2.3%	1.5%	2.0%	3.0%	2.2%
MGE Energy	4.4%	4.0%	4.0%	5.5%	4.5%
NV Energy	3.6%	3.0%	3.5%	4.5%	3.7%
Northeast Utilities	5.0%	5.0%	5.5%	5.5%	5.3%
Otter Tail Corp.	nmf	nmf	nmf	0.5%	0.5%
Pepco Holdings	0.8%	1.0%	1.0%	2.5%	1.3%
PG&E Corp.	3.9%	2.5%	5.5%	5.5%	4.4%
Pinnacle West Capital	3.1%	2.5%	3.0%	3.0%	2.9%
PNM Resources	1.3%	2.0%	3.0%	3.0%	2.3%
Progress Energy	1.4%	1.5%	1.5%	2.5%	1.7%
Public Serv. Enterprise	9.0%	6.5%	5.5%	7.0%	7.0%
SCANA Corp.	3.8%	3.5%	3.5%	4.0%	3.7%
TECO Energy	3.1%	4.5%	5.5%	5.5%	4.7%
UIL Holdings	1.7%	1.0%	1.0%	2.5%	1.6%
Vectren Corp.	1.5%	1.5%	2.5%	3.5%	2.3%
Westar Energy	2.8%	2.0%	2.5%	4.0%	2.8%
Xcel Energy Inc.	3.6%	4.0%	4.5%	4.5%	4.2%
					3.5%
Duke Energy	2.1%	2.5%	2.5%	3.0%	2.5%

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011

Duke Energy

Docket No. 2011-271-E

Comparable Group Includes Companies with Merger Activity

Company	% Retained to Common Equity				
	2010	2011E	2012E	14-16E	Average
ALLETE	1.5%	3.0%	3.0%	3.5%	2.8%
Alliant Energy	3.8%	4.0%	4.0%	4.5%	4.1%
Amer. Elec. Power	3.1%	4.5%	4.5%	5.0%	4.3%
Ameren Corp.	3.8%	2.5%	2.5%	2.5%	2.8%
Black Hills	0.7%	1.5%	2.0%	2.5%	1.7%
Cen. Vermont Pub. Serv.	3.4%	3.5%	3.5%	3.5%	3.5%
CenterPoint Energy	3.8%	4.0%	4.0%	4.0%	4.0%
CH Energy Group	2.2%	2.5%	2.0%	3.0%	2.4%
Cleco Corp.	6.1%	5.5%	5.0%	4.0%	5.2%
CMS Energy Corp.	6.9%	5.5%	5.5%	5.0%	5.7%
Consol. Edison	3.3%	3.0%	3.0%	3.5%	3.2%
DTE Energy	4.0%	3.0%	3.0%	3.5%	3.4%
Edison Int'l	6.5%	4.5%	4.5%	4.5%	5.0%
G't Plains Energy	3.4%	2.0%	2.5%	3.0%	2.7%
Hawaiian Elec.	1.4%	1.0%	1.5%	4.0%	2.0%
IDACORP, Inc.	5.5%	5.0%	5.5%	4.5%	5.1%
Integrys Energy	2.3%	1.5%	2.0%	3.0%	2.2%
MGE Energy	4.4%	4.0%	4.0%	5.5%	4.5%
NV Energy	3.6%	3.0%	3.5%	4.5%	3.7%
Otter Tail Corp.	nmf	nmf	nmf	0.5%	0.5%
Pepco Holdings	0.8%	1.0%	1.0%	2.5%	1.3%
PG&E Corp.	3.9%	2.5%	5.5%	5.5%	4.4%
Pinnacle West Capital	3.1%	2.5%	3.0%	3.0%	2.9%
PNM Resources	1.3%	2.0%	3.0%	3.0%	2.3%
Public Serv. Enterprise	9.0%	6.5%	5.5%	7.0%	7.0%
SCANA Corp.	3.8%	3.5%	3.5%	4.0%	3.7%
TECO Energy	3.1%	4.5%	5.5%	5.5%	4.7%
UIL Holdings	1.7%	1.0%	1.0%	2.5%	1.6%
Vectren Corp.	1.5%	1.5%	2.5%	3.5%	2.3%
Westar Energy	2.8%	2.0%	2.5%	4.0%	2.8%
Xcel Energy Inc.	3.6%	4.0%	4.5%	4.5%	4.2%
					3.4%
Duke Energy	2.1%	2.5%	2.5%	3.0%	2.5%

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011

Duke Energy

Docket No. 2011-271-E

Comparable Group Includes No Companies with Merger Activity

Company	% Return on Common Equity 2010	2011E	2012E	2014E-2016E
ALLETE	7.7%	9.0%	9.0%	9.5%
Alliant Energy	10.5%	11.0%	11.0%	12.0%
Amer. Elec. Power	9.1%	10.5%	10.5%	10.5%
Ameren Corp.	8.6%	7.0%	7.0%	7.0%
Black Hills	5.9%	6.5%	7.0%	7.5%
Cen. Vermont Pub. Serv.	7.5%	7.5%	8.0%	8.0%
CenterPoint Energy	13.8%	12.0%	12.0%	11.5%
CH Energy Group	8.6%	8.5%	8.5%	9.0%
Cleco Corp.	10.6%	10.0%	10.0%	9.5%
CMS Energy Corp.	12.5%	12.5%	12.5%	12.5%
Consol. Edison	9.0%	9.5%	9.0%	9.5%
Constellation Energy	4.1%	6.0%	5.5%	7.5%
DTE Energy	9.4%	9.0%	9.0%	9.0%
Edison Int'l	10.4%	8.0%	8.5%	8.0%
Exelon Corp.	18.9%	17.5%	12.5%	15.0%
G't Plains Energy	7.3%	5.5%	6.5%	7.5%
Hawaiian Elec.	7.7%	8.5%	9.0%	10.5%
IDACORP, Inc.	9.3%	9.0%	9.0%	8.5%
Integrys Energy	8.7%	9.0%	9.0%	9.5%
MGE Energy	11.0%	10.5%	9.5%	12.0%
NV Energy	6.8%	6.0%	7.0%	8.5%
Northeast Utilities	9.8%	10.0%	10.5%	10.0%
Otter Tail Corp.	2.2%	4.0%	5.0%	7.0%
Pepco Holdings	6.5%	6.5%	6.0%	7.5%
PG&E Corp.	9.7%	8.5%	11.0%	11.5%
Pinnacle West Capital	9.0%	8.5%	9.0%	9.0%
PNM Resources	4.3%	4.5%	6.5%	6.5%
Progress Energy	8.60%	8.50%	8.50%	9.00%
Public Serv. Enterprise	16.2%	13.0%	12.0%	12.5%
SCANA Corp.	10.2%	10.0%	9.5%	9.5%
TECO Energy	11.2%	12.5%	13.5%	13.0%
UIL Holdings	6.5%	8.5%	8.5%	9.0%
Vectren Corp.	9.3%	9.5%	10.0%	11.0%
Westar Energy	8.2%	7.5%	8.5%	10.0%
Xcel Energy Inc.	8.9%	10.0%	10.0%	10.0%
Average	**9.1%**	**9.0%**	**9.1%**	**9.7%**
Duke Energy	7.8%	8.0%	8.0%	8.5%

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011

Duke Energy
Docket No. 2011-271-E
Comparable Group Includes No Companies with Merger Activity

Company	% Return on Common Equity			
	2010	2011E	2012E	2014E-2016E
ALLETE	7.7%	9.0%	9.0%	9.5%
Alliant Energy	10.5%	11.0%	11.0%	12.0%
Amer. Elec. Power	9.1%	10.5%	10.5%	10.5%
Ameren Corp.	8.6%	7.0%	7.0%	7.0%
Black Hills	5.9%	6.5%	7.0%	7.5%
Cen. Vermont Pub. Serv.	7.5%	7.5%	8.0%	8.0%
CenterPoint Energy	13.8%	12.0%	12.0%	11.5%
CH Energy Group	8.6%	8.5%	8.5%	9.0%
Cleco Corp.	10.6%	10.0%	10.0%	9.5%
CMS Energy Corp.	12.5%	12.5%	12.5%	12.5%
Consol. Edison	9.0%	9.5%	9.0%	9.5%
DTE Energy	9.4%	9.0%	9.0%	9.0%
Edison Int'l	10.4%	8.0%	8.5%	8.0%
G't Plains Energy	7.3%	5.5%	6.5%	7.5%
Hawaiian Elec.	7.7%	8.5%	9.0%	10.5%
IDACORP, Inc.	9.3%	9.0%	9.0%	8.5%
Integrys Energy	8.7%	9.0%	9.0%	9.5%
MGE Energy	11.0%	10.5%	9.5%	12.0%
NV Energy	6.8%	6.0%	7.0%	8.5%
Otter Tail Corp.	2.2%	4.0%	5.0%	7.0%
Pepco Holdings	6.5%	6.5%	6.0%	7.5%
PG&E Corp.	9.7%	8.5%	11.0%	11.5%
Pinnacle West Capital	9.0%	8.5%	9.0%	9.0%
PNM Resources	4.3%	4.5%	6.5%	6.5%
Public Serv. Enterprise	16.2%	13.0%	12.0%	12.5%
SCANA Corp.	10.2%	10.0%	9.5%	9.5%
TECO Energy	11.2%	12.5%	13.5%	13.0%
UIL Holdings	6.5%	8.5%	8.5%	9.0%
Vectren Corp.	9.3%	9.5%	10.0%	11.0%
Westar Energy	8.2%	7.5%	8.5%	10.0%
Xcel Energy Inc.	8.9%	10.0%	10.0%	10.0%
Average	**8.9%**	**8.8%**	**9.1%**	**9.6%**
Duke Energy	7.8%	8.0%	8.0%	8.5%

Source: Value Line Investment Surveys of Aug. 5, 2011; Aug. 26, 2011; and Sept. 23, 2011

Duke Energy Carolinas

Docket No. 2011-271-E

as of Dec. 31, 2010

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-term Debt	47.00%	5.41%	2.54%
Common Equity	53.00%	9.50%	5.04%
Total Capitalization	100.00%		7.58%

APPENDIX A

Appendix A

Kevin W. O'Donnell, CFA
President
Nova Energy Consultants, Inc.
1350 SE Maynard Rd.
Suite 101
Cary, NC 27511

Education

I received a B.S. degree in Civil Engineering - Construction Option from North Carolina State University in May of 1982 and a Masters of Business Administration in Finance from Florida State University in August of 1984.

Professional Certification

I am a Chartered Financial Analyst (CFA) and a member of the Association of Investment Management and Research.

Work Experience

In September of 1984, I joined the Public Staff of the North Carolina Utilities Commission as a Public Utilities Engineer in the Natural Gas Division. In December of 1984, I transferred to the Public Staff's Economic Research Division and held the position of Public Utility Financial Analyst. In September of 1991, I joined Booth & Associates, Inc., a Raleigh, North Carolina, based electrical engineering firm, as a Senior Financial Analyst. I stayed in this position until June 1994, when I accepted employment as the Director of Retail Rates for the North Carolina Electric Membership Corporation. In January 1995, I formed Nova Utility Services, Inc., an energy consulting firm. In May of 1999, I changed the name of Nova Utility Services, Inc. to Nova Energy Consultants, Inc.

Along with my work with Nova Energy Consultants, Inc., I also provide financial consulting services to MAKROD Investment Associates of Verona, NJ. MAKROD is a money management firm that specializes in portfolio management services for high wealth individuals and institutional investors.

I have also worked with North Carolina and South Carolina municipalities in presenting comments to the Federal Energy Regulatory Commission regarding the opening of the wholesale power markets in the Carolinas.

Publications

I have also published the following articles: Municipal Aggregation: The Future is Today, *Public Utilities Fortnightly*, October 1, 1995; Small Town, Big Price Cuts, *Energy Buyers Guide*, January 1, 1997; and Worth the Wait, But Still at Risk, *Public Utilities Fortnightly*, May 1, 2000. All of these articles dealt with my firm's experience in working with small towns that purchase their power supplies in the open wholesale power markets.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1992	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1992	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1995	Pennsylvania & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA C	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA C	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progres	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commissio	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Nat	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Nat	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Nat	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel applicatoin
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	Application to share net revenues from certain wholesale power transactions

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client Employer	Case Issues
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, return on equity, capital structure

APPENDIX B

On-Peak kWh	$ 0.04460 kWh	$ 0.04150 kWh
Off-Peak kWh	$ 0.04100 kWh	$ 0.03900 kWh

SCHEDULE CO2C - Coincident Peak Rate 08-2C

Effective Date 7/1/2011 (250-750kW)	SUMMER MONTHS (June - September)	WINTER MONTHS (October - May)
FACILITY CHARGE	$ 261.38	$ 261.38
MONTHLY BILLING DEMAND	$ 17.00 kW	$ 4.50 kW
EXCESS DEMAND	$ 3.25 kW	$ 3.25 kW
ENERGY CHARGE		
On-Peak kWh	$ 0.04300 kWh	$ 0.04000 kWh
Off-Peak kWh	$ 0.04080 kWh	$ 0.03900 kWh

SCHEDULE CO2I - Coincident Peak Rate 08-2I

Effective Date 7/1/2011 (500-2000kW)	SUMMER MONTHS (June - September)	WINTER MONTHS (October - May)
FACILITY CHARGE	$ 261.38	$ 261.38
MONTHLY BILLING DEMAND	$ 15.50 kW	$ 4.00 kW
EXCESS DEMAND	$ 2.50 kW	$ 2.50 kW
ENERGY CHARGE		
On-Peak kWh	$ 0.03975 kWh	$ 0.03825 kWh
Off-Peak kWh	$ 0.03675 kWh	$ 0.03575 kWh

SCHEDULE CO3C - Coincident Peak Rate 08-3C

Effective Date 7/1/2011 (750kW+)	SUMMER MONTHS (June - September)	WINTER MONTHS (October - May)
FACILITY CHARGE	$ 261.38	$ 261.38
MONTHLY BILLING DEMAND	$ 17.00 kW	$ 4.50 kW
EXCESS DEMAND	$ 3.25 kW	$ 3.25 kW
ENERGY CHARGE		
On-Peak kWh	$ 0.04225 kWh	$ 0.04000 kWh
Off-Peak kWh	$ 0.03900 kWh	$ 0.03800 kWh

SCHEDULE CO3I - Coincident Peak Rate 08-3I

Effective Date 7/1/2011 (2000kW+)	SUMMER MONTHS (June - September)	WINTER MONTHS (October - May)
FACILITY CHARGE	$ 261.38	$ 261.38
MONTHLY BILLING DEMAND	$ 15.50 kW	$ 4.00 kW
EXCESS DEMAND	$ 2.50 kW	$ 2.50 kW
ENERGY CHARGE		
On-Peak kWh	$ 0.03975 kWh	$ 0.03825 kWh
Off-Peak kWh	$ 0.03675 kWh	$ 0.03575 kWh

SCHEDULE CO4C - Coincident Peak Rate 08-4C

Effective Date 7/1/2011 (4000kW+)	SUMMER MONTHS (June - September)	WINTER MONTHS (October - May)
FACILITY CHARGE	$ 261.38	$ 261.38
MONTHLY BILLING DEMAND	$ 16.00 kW	$ 3.00 kW
EXCESS DEMAND	$ 1.75 kW	$ 1.75 kW
ENERGY CHARGE		
On-Peak kWh	$ 0.04000 kWh	$ 0.03675 kWh
Off-Peak kWh	$ 0.03400 kWh	$ 0.03355 kWh

SCHEDULE IS - Small Industrial Service

Effective Date 7/1/2011	SUMMER MONTHS	WINTER MONTHS

CERTIFICATE OF SERVICE

The undersigned employee of Elliott & Elliott, P.A. does hereby certify that (s)he has served below listed parties with a copy of the pleading(s) indicated below by mailing a copy of same to them in the United States mail, by regular mail, with sufficient postage affixed thereto and return address clearly marked on the date indicated below:

RE:	Application Duke Energy Carolinas, LLC for Authority to Adjust and Increase the Company's Electric Rates and Charges
DOCKET NO.:	2011-271-E
PARTIES SERVED:	Timika Shafeek-Horton, Esquire Duke Energy Carolinas, LLC P. O. Box 1006/EC03T Charlotte, NC 28201
	Shannon B. Hudson, Esquire Courtney D. Edwards, Esquire Office of Regulatory Staff 1401 Main Street, Ste. 900 Columbia, SC 29201
	Frank R. Ellerbe, III, Esquire Bonnie D. Shealy, Esquire Robinson, McFadden & Moore, P.C. P. O. Box 944 Columbia, SC 29202
	Heather S. Smith, Esquire Duke Energy Carolinas, LLC 550 S. Tryon St., DEC45A Charlotte, NC 28202
	Richard L. Whitt, Esquire Timothy F. Rogers, Esquire Austin & Rogers, PA P. O. Box 11716 Columbia, SC 29201

Thomas L. Moses, Esquire
Monahan and Moses, LLC
13-B W. Washington Street
Greenville, SC 29601

Holly Rachel Smith, Esquire
Russell W. Ray, PLLC
Hitt Business Center
3803 Rectortown Road
Marshall, VA 20115

PLEADING: DIRECT TESTIMONY OF KEVIN W. O'DONNELL

November 14, 2011

Jackie C. Livingston

Jackie C. Livingston, Paralegal